FINANCING THE ENERGY TRANSITION

The impact of a changing power sector on investors

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Lena Hörnlein

from Germany

approved in April 2020 at the request of

Prof. Dr. Marc Chesney

Prof. Dr. Stefano Battiston

Prof. Dr. Rolf Wüstenhagen

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Chapter 1

Introduction

1.1 The energy transition

Today renewable energies dominate investments and capacity additions in the electricity sector worldwide. In 2018, global investment in renewable energy capacity[1] was about USD 273 billion, markedly higher than investments in fossil and nuclear generation capacity combined. The past decade (2010-2019) is estimated to have attracted USD 2.6 trillion in investments in renewables, more than triple the amount invested in renewables during the previous decade.

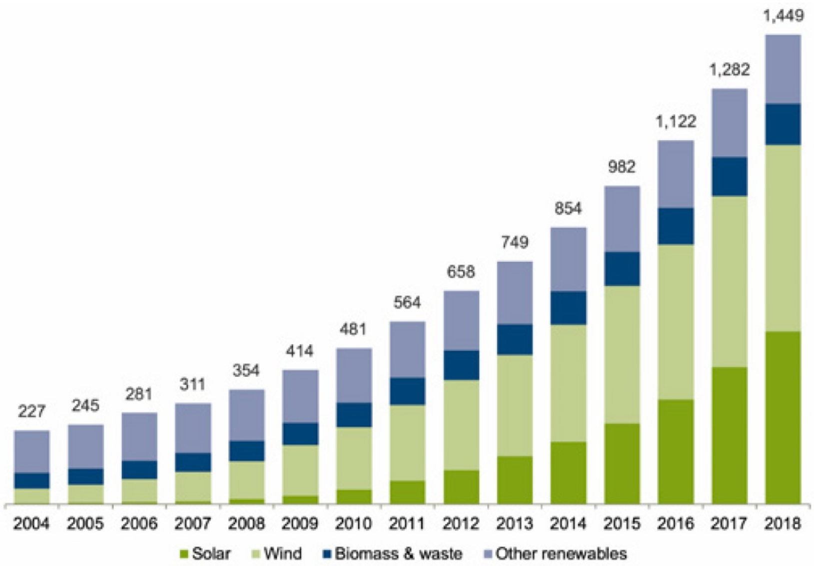


Figure 1.1.1: Global capacity in renewable power 2004-2018 in GW. Source: Frankfurt School et al 2019.

Solar has seen higher investments in the past decade than any other renewable, fossil or nuclear technology with USD 1.3 trillion invested and 638 GW of capacity added. In 2018, solar attracted USD 134 billion in investments for 108 GW of capacity additions, followed by wind (USD 130 billion

[1] This and later global and European estimates exclude large hydro of more than 50 MW "partly because this is a long-established technology in the generation mix of many countries. In addition it is difficult to track the trends in large hydro investment because of the long – sometimes decade-or-more – construction periods. Often big dams commence construction, suffer delays or even stoppages, and may be part-financed at different times." (Frankfurt School et al 2018).

for 50 GW) and gas-fired generation (USD 49 billion for 42 GW). This has led to a steep upwards curve in capacity provided by renewable power (figure 1.1.1).

In 2010 only 6.1% of global power generation and 10.2% of global power capacity was provided by renewables, figures that both more than doubled during the past decade (Frankfurt School et al 2019, IEA 2019). Cost reductions played an important role in this transition: levelized cost of electricity from solar photovoltaics came down by 81%, from onshore wind by 46% and from offshore wind by 44%, making renewable technologies today the cheapest option for new generation in many locations (Frankfurt School et al 2019).

This thesis focuses on Germany, as the country has long been at the forefront of the power sector's transition to renewables globally. The German government adopted grid priority and 20-year fixed tariffs differentiated by renewable energy technology as early as 2000. As a result, renewable electricity capacity was at 49.4% and generation at 32.5% in 2018,[2] up from 2% generation in 2000[3] and more than double the global average numbers of 21.0% and 12.9% (figure 1.1.2).

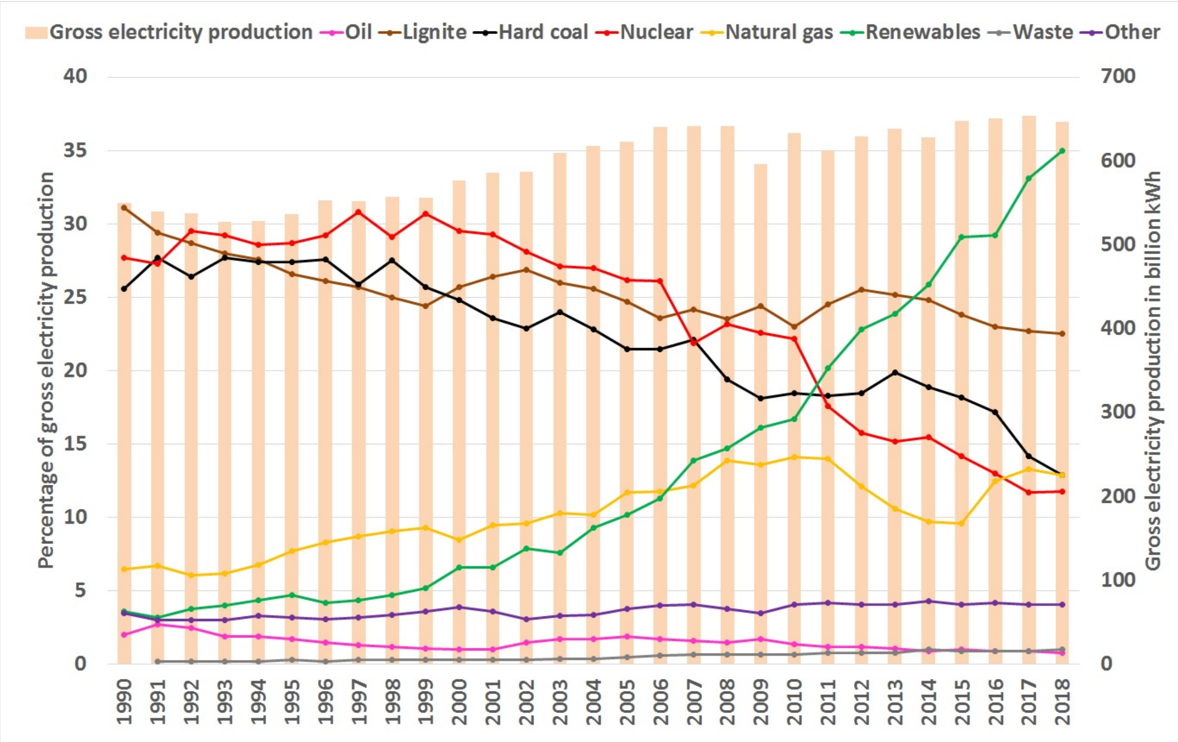


Figure 1.1.2: Gross electricty production from different technologies in Germany. Source: Own illustration based on BDEW 2019.

At the same time, Germany embarked on an exit from nuclear energy, a technology that is largely emissions-free but was regarded as risky by large parts of the German population and turned out to be difficult to value in terms of decommissioning and storage costs. Germany's reduction in electricity generation from nuclear and hard coal was balanced out by the increase in renewables.

[2]German estimates are conservative as they do not include any small- or large-scale hydro, while global numbers only exclude large-scale hydro.

[3]The share of renewable power capacity in Germany is not available before 2008.

However, lignite generation - the most climate-damaging technology - remained largely stable, while gas-fired generation showed a long-term increasing, although at times volatile, trend leading to only slowly decreasing greenhouse gas emissions (figure 1.1.2).
The revolution in the electricity sector in Germany was accompanied by heavy impacts on incumbent electric utilities and a radical change in the investor landscape. This change is described in more detail in section 1.4.

1.2 Motivation of this thesis

Germany's power sector investor landscape has fundamentally changed in the past years, as will be described in more detail in section 1.4. The goal of this PhD thesis is to better understand the impact of the energy transition on different types of investors in the power sector.
Why do we care to know what the impacts of a changing power sector are on investors?
Gas-fired power generation capacity is widely praised as a relatively low-carbon transition technology, because it could, due to its ramping flexibility, also deal with a rising share of weather-fluctuating wind and solar in the grid. Yet, in Germany the increase of renewables came with a ramp-down of gas-fired power plants due to investors' reaction to depressed power prices - partly a result of the energy transition.
The big four German incumbent utilities were taken by surprise by the energy transition, lost market share and in 2015 faced the risk of bankruptcy. Being still responsible for a third of German power generation capacity, policy makers feared that a default of a big utility posed a systemic risk to the energy sector with major implications for the German economy as a whole.
Financial and institutional investors, on the other hand, have increasingly invested in the operating phase of renewable energy assets. With the market getting more competitive and governments wanting to phase out policy support, it is now crucial for both investors and policy makers to better understand the key risk factors of investing in energy assets. Only if financial investors' needs are thoroughly understood and taken into account when devising new policies, can this major new source of low-cost capital be tapped in order to reach ambitious renewable energy deployment and climate goals.
For these reasons, this thesis seeks to understand the behaviour and needs of private investors in the energy sector and to explore lessons learned in Germany that are applicable to other countries on a similar path away from nuclear and fossils to more renewable electricity sources.

1.3 Contribution to the literature

This thesis is part of the energy finance literature analysing investments in the electricity sector. A growing number of research articles are dedicated to the impact of the energy transition on investment and investor behaviour. However, most research to date is grounded in techno-economic modelling (e.g. Santos et al 2017; Hirth 2018), management science (e.g. Frei et al 2018; Ossenbrink et al 2019), innovation theory (e.g. Egli et al 2018; Mazzucato and Semienuk 2018) or sociology (e.g. Kungl and Geels 2018). Only a modest but growing body of literature analyses power sector investment relying on finance theory (e.g. Sen and Schickfus 2017; Steffen 2018), methodologies (e.g. Kitzing et al 2017; Vargas and Chesney 2018) or addressing core finance questions (e.g. Salm and Wüstenhagen 2018; Schmidt et al 2019).

The thesis contributes to this body of literature by building on various theories and methodologies from finance research. Chapter 2 uses the real options modelling approach from finance to investigate the impact of low power prices on operators of gas-fired power plants. Chapter 3 investigates the corporate restructurings by two main German utilities drawing on the divestiture literature and also makes a modest conceptual contribution to this field of corporate finance. Chapter 4 employs the well-known discounted cash-flow model from corporate finance to analyse the impacts of different risk factors on a financial investor's wind park portfolio.

1.4 Background: Germany's power market investor landscape is changing

Two main developments can be observed in the German power sector investor landscape in the past years. The first concerns the retreat of traditional utilities (section 1.4.1) and the second the advent of new investor types (section 1.4.2).

1.4.1 Traditional utilities retreat

The four main German utilities - EON, RWE, EnBW and Vattenfall - had dominated the power sector since the liberalisation of electricity markets in the late 1990s.

They came late, however, to the renewables boom. Between 2009 and 2015,[4] they more than doubled the share of renewables in their overall portfolio, from 3.0% to 6.8% on average. But in Germany overall, renewables' share of total power generation capacity had almost doubled from an already much higher base in the same time frame: from 27.1% to 45.0%. Utilities' investments did not catch up with the overall German trend towards renewables already under way. The four utili-

[4] In 2016, Vattenfall sold its German lignite operations and EON and RWE underwent large restructurings, which are analysed in chapter 3. Therefore, market shares from 2016 are no longer comparable to previous years.

ties' share of total German renewable capacity stayed roughly stable at around 5.0% between 2009 and 2015 (figure 1.4.1a).

Since electricity production from fossil fuels and nuclear energy starkly decreased and renewables were the only growth sector (figure 1.1.2), the big four utilities lost market share overall. Between 2009 and 2015, their contribution to total German power generation capacity fell from 57% to 34% (figure 1.4.1b).

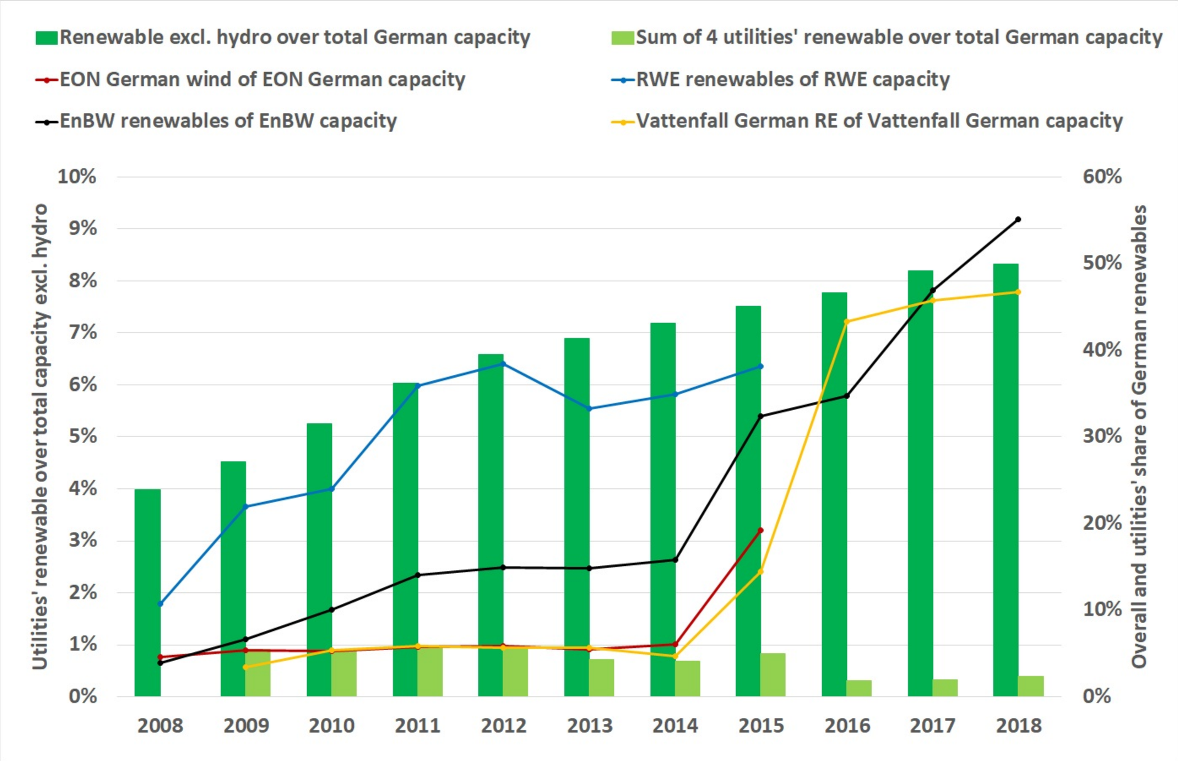
Why did utilities not invest in renewable energies more pro-actively and thereby secured their market share in a transforming power sector?

The reasons for this are manifold, some of which are examined in this thesis. First, utilities' experience in fossil fuel and nuclear assets was not directly applicable to renewables. Wind and solar assets are much smaller and more decentralised. Second, in the early 2000s, high power prices meant that conventional power plants offered higher returns compared to the governmental feed-in tariffs for renewables. This topic is discussed in chapter 3.[5]

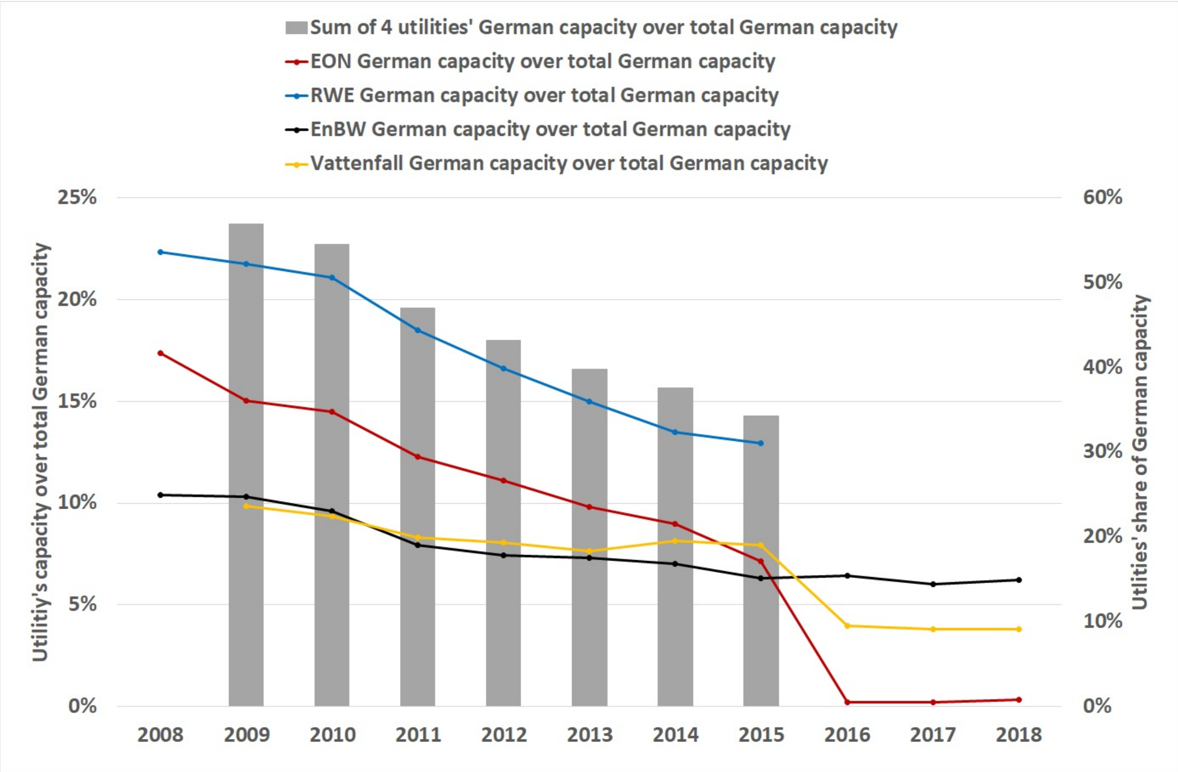
In the late 2000s, low electricity prices in Europe - and particularly in Germany - led to low profits for conventional power plant operators. Utilities had to ramp down and in some cases mothball the power plants with highest marginal costs in order to limit their losses. In the case of Germany, these were mainly the relatively climate-friendly gas-fired assets, a development which is illustrated in chapter 2. Losses at utilities' conventional generation segments meant less capital expenditure available for renewables. On top of this, German utilities also suffered from the nuclear exit. This is examined in chapter 3.

Both chapters 2 and 3 shed light on the fate of existing power plant operators during the German energy transition. Lessons learned could be applied more broadly beyond Germany, as utilities all over Europe to a certain extent face these same problems (Annex and Typoltova 2018).

[5] For retail investors, the opposite was the case: small assets suited their small amounts of capital available to invest; at the same time, feed-in tariffs offered attractive returns compared to alternative investments available to retail investors.



(a) Overall and big four utilities' share of renewable generation capacity in Germany.



(b) Big four utilities' share of German generation capacity.

Figure 1.4.1: Big four utilities' role in German power generation capacity. Source: Own illustration based on annual reports of EON, RWE, EnBW, Vattenfall 2005-2019; BMWi 2018; Bundesnetzagentur 2019.

1.4.2 New investors come in

Who took the utilities' place as dominant power plant investors and asset owners in the growing renewables market? In Germany, these were mainly retail investors (31.5% of renewable generation assets in 2016), project developers (14.4%), financial investors like banks and funds, and industrials (each 13.4%) (see figure 1.4.2).

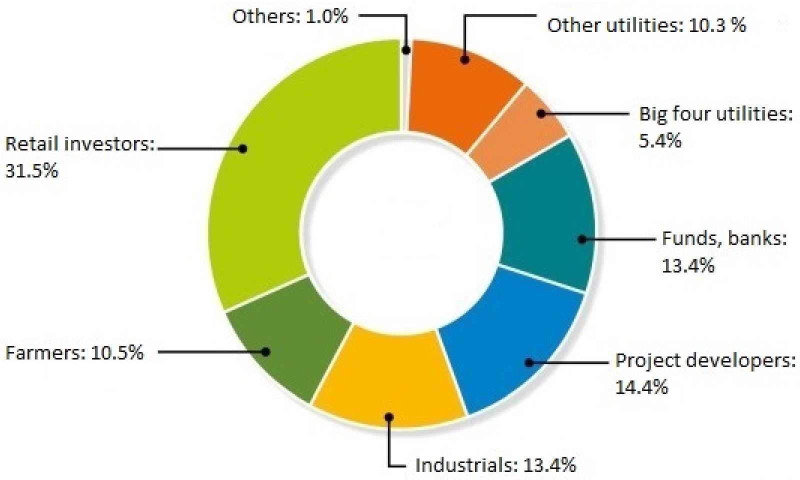


Figure 1.4.2: Owners of renewable energy assets in MW in Germany in 2016. Source: trend:research 2017.

Whereas project developers specialise in building renewable power plants and often sell them on to other investors after construction (Hostert 2016), the other investor types usually hold the assets longer-term, sometimes over their entire operational life of more than 20 years. Distressed utilities also discovered the build-sell-operate model as a way to recycle funds and generate profits by selling early-stage renewable assets to institutional investors (McCrone 2017). This explains the high share of financial investors in Germany, who usually do not develop projects themselves but enter after construction.

Looking at Europe, institutional investors like pension funds and insurance companies committed a growing amount to renewable energy projects in the past years. Their investments hit a record in 2017[6] of USD 9.9 billion, up 42% on 2016. Growth can especially be noted in direct investments, project bonds and private equity funds (figure 1.4.3).[7]

In summary, one can observe a growing interest by institutional investors in European renewable energy private equity assets. Chapter 4 focuses on an institutional investor's point of view by analysing risk factors during a wind power plant acquisition.

[6] 2018 numbers are not available.

[7] The data excludes the sale of equity by companies that not only invest in renewables, e.g. utilities. However, as the previous section showed, at least in Germany the big utilities were slow at investing in renewables. And because non-utilities often finance renewable assets not on balance sheet but via special purpose vehicles (Steffen 2018), the graph might indicate a general trend towards private equity and project bonds in order to gain exposure to the growing renewables market.

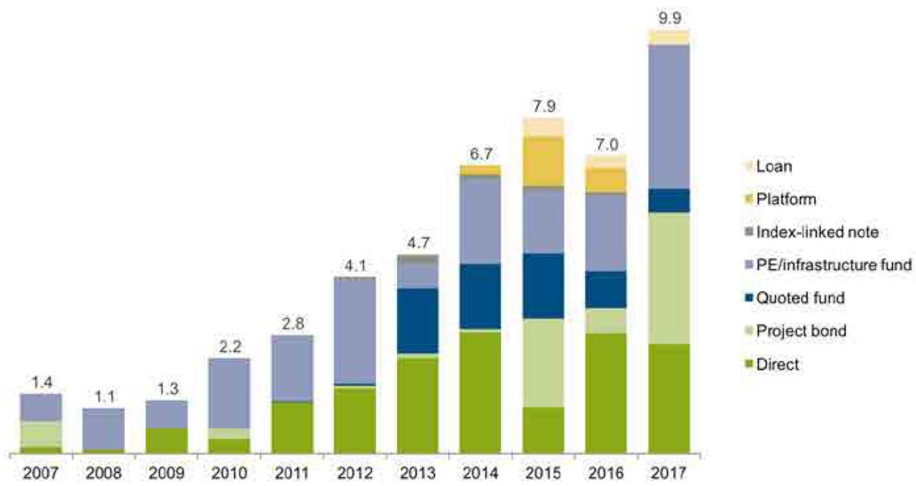


Figure 1.4.3: Institutional investor commitments to European renewable energy projects in USD billion. Source: Frankfurt School et al 2018.

What are the reasons for institutional investment in the growing renewables sector? First, renewable energy assets have some inherent qualities that make them attractive to institutional investors. They have comparatively low operational risk: solar and wind power plants, unlike nuclear or fossil fuel ones, carry no fuel price risk. Once built the main risk factors are weather variability and power prices (Awerbuch 2000).

Second, many European countries decided to cancel out power price risk altogether by providing up to 20 years fixed remuneration for each kilowatt-hour produced, the so-called feed-in tariffs (FiT). These suited institutional investors' preference for low-risk assets that have stable long-term cash-flows and a low correlation with the market (Ernst & Young 2014; Allianz 2017).

Third, high levels of liquidity in financial markets since the 2008 crisis pushed international interest rates and bond yields to record lows. This forced institutional investors to look at alternative investments, among those renewables (Gatzert and Kosub 2016; Annex and Typoltova 2018). A major European utility's CEO recently said that low interest rates were a major reason why utilities could sell renewable assets to institutional investors at a profit (Collins and McCrone 2018).

A fourth reason for institutional investors' interest in renewables might also be the recent public pressure to increase their portfolio's sustainability scores (McCrone 2017, also examined in chapter 3).

Overall, renewable energies developed into an attractive market for institutional investors. In recent years, however, competition increased as the market professionalized and governments begun to introduce renewable capacity auctions in order to cap capacity built and slowly expose renewables to more price risk. As a result, equity return expectations have fallen across Europe (Metcalfe 2019). Institutional investors therefore have to model their risk exposure in renewable energy assets more thoroughly, a topic explored in chapter 4.

1.5 Summary of research methods, results and contribution

This section summarizes research methods, results, contribution to the academic literature and policy discussions of the three papers that constitute the main chapters (2-4) of this thesis.

1.5.1 The value of gas-fired power plants in markets with high shares of renewable energy - A real options application

The first paper deals with gas-fired power generation capacity, a technology that is widely praised as a relatively low-carbon transition technology, because it could, due to its ramping flexibility, also deal with a rising share of weather-fluctuating wind and solar in the grid. Yet, in Germany the increase of renewables came with a sharp decrease of electricity from gas-fired power plants in the early 2010s.

Why? Key to understanding this phenomenon are the operational decisions of power plant operators.[8] Operators maximise profits by comparing short-run operational costs with the spread of power and gas prices on the market. A real options model is chosen to model an operator's decision to switch on, ramp up or down or switch off the power plant on an hourly basis.

A literature review of existing real options models on operators' decision making results in the development of a new model that improves upon existing ones in several ways. Electricity and gas prices are modelled as a two-dimensional stochastic process, each component consisting of the sum of a deterministic seasonal part and a mean-reverting process. Several types of gas-fired power plants are modelled by incorporating different ramping times and costs. Two types of model are developed, one with daily operating decisions and one with hourly ones.

The models are run with recent power and gas prices from Germany. The hourly model replicates operators' decision making very well, as the results trace the decline between 2013 and 2015 and subsequent come-back of gas-fired electricity, when German power prices recovered.

The comparison of the results with daily and with hourly ramping show that time step size is highly relevant for gas-fired generation models. Average profits in the hourly model are more than double what is derived with a daily model. Likewise, including ramping times and costs yield significantly lower profits than assuming immediate costless availability. The sensitivity of overall profits, including investment costs, to changes in the discount rate illustrates the importance of financing costs due to the longevity of electricity generation assets.

The paper contributes to a better understanding of the choices operators and investors face in the electricity market. Even though temporarily recovered power prices brought gas-fired generation back into profitability in Germany, the question of whether a market model based on marginal

[8] In the case of Germany, mainly utilities.

costs sufficiently incentivises low-carbon power generation, is still highly relevant to the energy transition across Europe.

1.5.2 Utility divestitures in Germany - A case study of corporate financial strategies and energy transition risk

In recent years, the two biggest German electric utilities, EON and RWE, had the most difficult times of their history. From 2011 to 2015 they each wrote off more than 13% of their book asset value and lost between 70% (EON) and 80% (RWE) of their market capitalisation. EON and RWE, until then integrated firms spanning the whole energy value chain, responded with two of the most dramatic restructuring moves in recent German corporate history and in the history of privately-run European utilities as a whole. EON spun off its fossil fuel and trading segments, while RWE carved out its renewable energy, retail and grid business.

Why did EON and RWE divest? While the firms themselves argued that the restructurings would bring about a large array of benefits, encompassing all possible advantages ever discussed in the context of divestitures, this second paper critically assesses different hypotheses from the corporate finance literature and establishes the main reasons responsible for the decisions.

A literature review first identifies four possible types of drivers for divestitures: operations and management, investing, financing and investor preferences. These drivers are then tested in the empirical case of the EON and RWE divestitures of 2016. A mixed methods approach is used: comparative descriptive statistics using a control group of European listed utilities; interviews with EON and RWE staff and management, analysts, journalists and academics; gray literature like annual reports, investor presentations and newspaper articles; and several event studies examining the effect of news items on EON's and RWE's share price and stocks traded.

The combination of methods converges in rejecting drivers related to operations, management and investing. The drivers related to investor preferences cannot sufficiently be distinguished from risk contamination.

The analysis supports debt overhang as a driver, since EON and RWE accumulated higher liabilities than their peers due to provisions for nuclear dismantling and storage. There is also strong evidence for risk contamination based on the firms' and subsidiaries' valuations pre- and post-divestiture, a share price event study and interviews. Likely sources of risk contamination are expected losses by fossil fuel-fired power plants and the acute risk of unmanageably high nuclear dismantling and especially storage costs linked to the German nuclear exit.

Utilities appear to have restructured to avoid further risk contamination of their healthy assets (renewables and grid infrastructure) by the conventional power generation business (fossil fuel and nuclear plants). Already weakened from record losses in their fossil fuel powered generation fleet due to low electricity prices, after 2011 the nuclear exit emerged as an additional challenge to the utilities. Investors doubted the adequacy of utilities provisions for decommissioning nuclear power plants and storing toxic waste, and feared major cost increases for which the utilities would be unlimitedly liable.

The paper uses existing research on divestitures in an empirical case that has implications for the evolution of European power markets. The results suggest that exiting conventional technologies as part of the transition to a more renewable energy mix can have substantial costs. If these are not clarified and allocated ex ante, policy makers find themselves forced to either burden tax payers or endanger utilities that are of systemic relevance to the energy sector.

1.5.3 The impact of production and macroeconomic risk on wind power equity returns - An analysis from a financial investor's perspective

Financial investors play an increasing role in the operational phase of renewable energy assets. In recent years, with substantial experience gained in construction, management and financing of renewable energy, the sector matured and competition between investors increased. Moreover, in Germany the first wind farms are approaching the end of their guaranteed feed-in tariff (FiT) period of 20 years, exposing operators to market price risk.

As a result, project evaluation techniques are maturing as well. In a competitive environment, asset managers have to accurately model asset returns in order to be able to offer a competitive price to project developers. On the other hand, they should not overpay for an asset and thereby impair their shareholders' returns. In this context, it is critical for industry investors to understand the sensitivity of equity returns to variations in production and macroeconomic factors.

In this last paper, four sources of risk for a wind park operator are examined. First, realised production in kilowatt-hours (kWh) is the biggest factor of uncertainty for any wind park. Second, for wind parks in Germany, market power prices are important after the guaranteed FiT period of 20 years. Third, inflation plays a role for power prices as well as operating costs, which are partly indexed. Fourth, after the end of the fixed interest period of their long-term loans, wind parks are exposed to interest rate risk. A discounted cash-flow model is used to examine how variations in these four risk factors impact equity returns.

The results show that, among the four risk factors, uncertainty in energy production has the highest impact on shareholder payouts, while power prices and the resulting market values of wind power have the second highest impact. Greater production or power prices ceteris paribus lead to greater revenues and thereby shareholder returns.

Inflation has a medium and generally positive impact on equity payout returns. A "bath tub curve" with the lowest return somewhere near the median can be observed for wind parks that opt to stay in the FiT for a long time. In this case there is no downside risk of inflation, as both lower and higher than expected inflation yields higher than expected returns. For wind parks operating mainly on the free market, on the other hand, low inflation yields a comparably low return as revenue losses due to lower than expected inflation are higher than opex savings.

Interest rates have a negative but small impact on shareholder payouts due to the relatively long fixation of interest rates for bank loans of 10 to 20 years. Interest rate risk is likely to rise, however, as loan tenors might shorten with the future reduction or phase-out of FiTs.

This last paper contributes to the energy economics and finance literature by presenting a financial investor perspective on production and macroeconomic risk in wind energy. Several strategies to partly mitigate the identified risks are suggested. To policy makers, the results offer a deeper understanding of equity investors' needs in order to harvest their available capital for reaching renewable energy targets. This understanding is crucial if policy makers want to reach climate targets while at the same time phasing out renewable energy policy support.

1.6 Summary and research outlook

This thesis contributes to the energy finance literature by investigating what the energy transition means for different investors in the German power sector.

It analyses the decision making of power plant operators and shows that low power prices - partly caused by renewable energies - might unintentionally push out flexible low-carbon generation first.

Using the case of the nuclear phase-out in Germany, the thesis demonstrated that the exit from a conventional technology might burden tax payers or endanger systemically relevant utilities, if conventional technology costs are not fully internalised early enough.

Finally, the thesis tests the sensitivity of an institutional investor's equity returns to variations in production and macroeconomic developments. It shows that in a market still largely shielded off from market price risk by 20-year guaranteed tariffs, shareholder returns strongly depend on power prices.

The thesis opens up many more research avenues. Concerning chapter 2, the question arises of whether "energy-only" markets, where power generation capacity is built and deployed mainly according to price setting mechanisms on the wholesale electricity exchange, lead to the right investment incentives in the long term.

Not only transition technologies like gas, with comparatively high marginal costs, might suffer. As solar and wind plants have very low marginal costs, a higher share of renewables overall leads to lower wholesale power prices. In addition, due to similar weather patterns across one region, wind and solar generation is strongly auto-correlated. Renewables' profitability might therefore cannibalise itself over time by causing very low wholesale prices precisely when a lot of renewable electricity is produced. Future research could devise an efficient power market design that ensures sufficient investment in renewable generation, electricity storage and demand-side measures to ensure a reliable and affordable electricity supply.

Regarding chapter 3, further research might look into how other sectors or sub-sectors can benefit from experiences like the German nuclear exit. The findings might be applied to coal mining and coal-fired power generation, a sector that the German government recently decided to phase-out as well. Another interesting case is mobility and the transformation of the market for combustion engines towards alternative engines and approaches to mobility.

Applied research in this field can devise realistic cost estimates for technology exit costs in each case and evaluate who would efficiently incur those. One the one hand, the principle should be "polluter pays". On the other hand, some regions or industries might be systemically relevant for an economy and - while future incentives should be structured in a fair way - it might sometimes be cost-effective to bail out certain regions or industries in order to make them ready for the challenges of a renewable future.

A related field of research could quantify the systemic risk present in the energy sector by devising methodologies and measures to conduct stress tests. This has already been done in finance research regarding the effect of interconnections among financial actors in the aftermath of the 2008 crisis and regarding the impact of climate risk on the financial system. A similar approach to the energy sector, with a stress test measuring the consequences of different transition scenarios on incumbent investors could be useful to derive low-cost policy recommendations.

As regards chapter 4, a question arising from the model is how both project developers and institutional investors will be able to earn their cost of capital in renewable energy markets with less or no policy support. What is the impact of the renewables market's transition from state-guaranteed FiTs to privately negotiated power purchase agreements (PPAs) between producers and corporate consumers? PPAs are long-term as well, but recent experience has shown that they are generally entered into for only five to 15 years, offering therefore a shorter hedge with more exposure to price risk. In addition, counter-party risk is higher than in the case of state-guaranteed tariffs.

Applied research can play an important role in examining the impact of PPAs on shareholder returns via increased power price and counter-party risk and a change in interest rates and loan tenures. Possible decreases in margins earned by manufacturers to power traders along the value chain also have to be taken into account. If policy makers want to completely phase out policy support to renewables while not losing institutional investors' available capital in order to reach ambitious renewable energy targets, further research in this field is crucial.

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Chapter 2

The value of gas-fired power plants in markets with high shares of renewable energy

A real options application

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Abstract

Using a real options model, this paper quantifies a gas-fired power plant's operating value and the value of a new investment against the background of a market transition to renewable electricity. The model is run with recent data for Germany's power sector and for different types of gas-fired power plants.

The result is twofold. First, the paper achieves a more realistic value by improving on existing models: it models electricity and gas prices as a two-dimensional stochastic process, each component consisting of the sum of a seasonal pattern and a mean-reverting process; it uses high granularity by modelling hourly time-steps; and it incorporates power plant ramping times and costs. Second, it compares two types of power plant models, one with daily and one with hourly operating decisions, and thereby quantifies the value of a plant's intraday flexibility. The hourly model replicates operators' and investors' decision making accurately. This is evidenced by the fact that the results trace current major developments like the recent decline and come-back of gas-fired generation in Germany.

The paper contributes to a better understanding of the choices operators and investors face in current electricity markets. In the absence of large scale storage solutions flexible supply of electricity, as provided by gas, is important in the transition to renewable energies in Germany and across Europe.

Key words— Real options; electricity; investment; gas-fired generation; energy transition.

2.1 Introduction

In Germany, the share of renewable energy in the power mix has increased rapidly in the past years: from 6 % renewable electricity generated in 2000 to around a third in 2017. As renewables do not have to pay for fuel, these energy sources produce power at very low marginal cost once power plants have been built. The increasing share of renewables, together with a range of other factors - low European emissions certificate and coal prices, the economic crisis - led to German power prices falling from above 50 Euros per megawatt hour (EUR/MWh) in the mid-2000s to record lows of below 30 EUR/MWh by 2016. While researchers disagree on the exact contribution of different price drivers, there is general agreement that in markets with little storage and dominated by renewables, low power prices could create a difficult environment for power sources with relatively high marginal cost, such as natural gas (Everts et al 2016; Bublitz et al 2017; Hirth 2018).

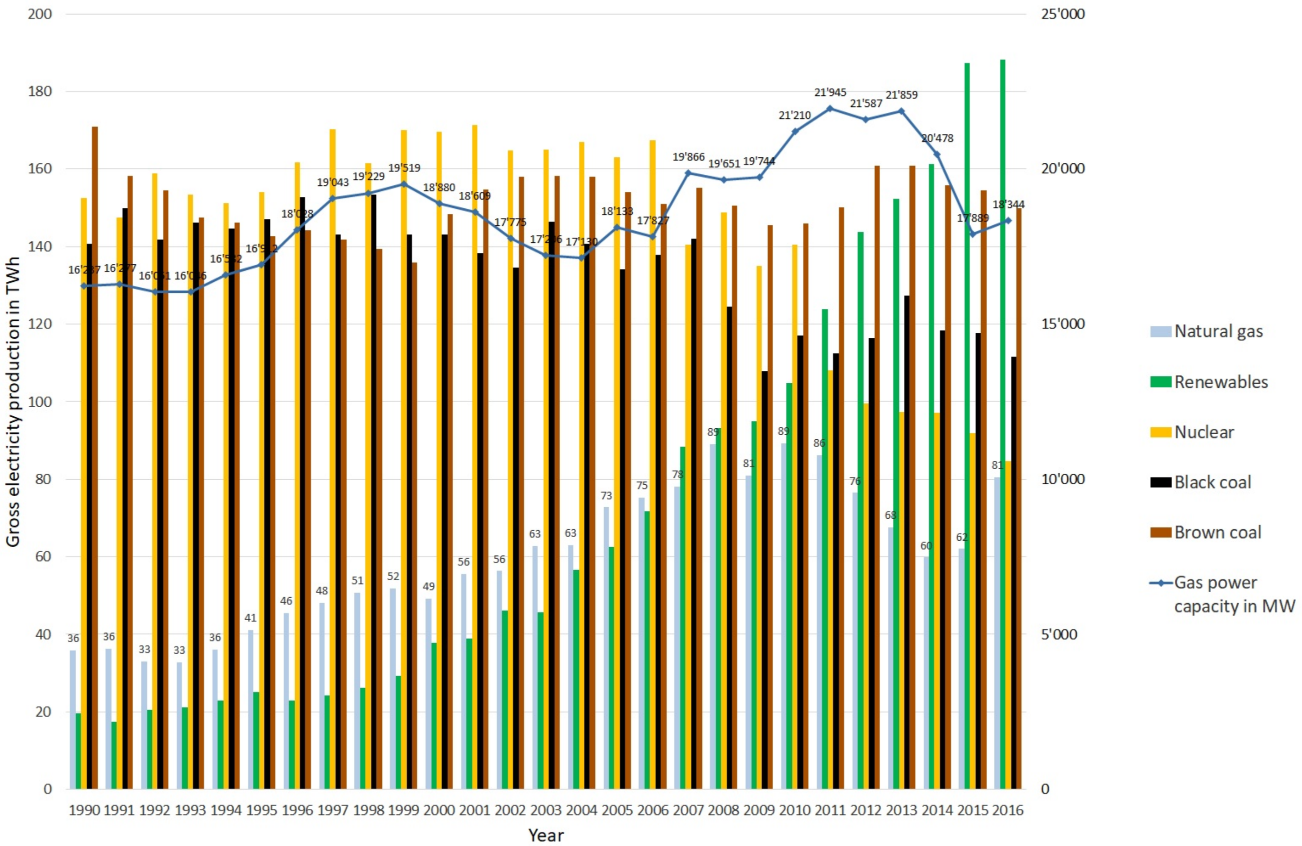


Figure 2.1.1: Gross electricity production according to main energy sources and gas-fired power capacity in Germany. Sources: Bundesnetzagentur 2014, Destatis 2017 (electricity production) and Umweltbundesamt 2017 (gas-fired power capacity).

In Germany, natural gas as a share of gross electricity production went down from 14% in 2011 to 10% in 2014, while lignite, the most CO_2-emitting source of electricity, remained relatively stable (figure 2.1.1). Only when natural gas prices declined and electricity prices eventually started recovering - partly due to recovering CO_2-prices - gas-fired power gained ground again: new plants were commissioned and production increased to 12% in 2016 (Bundesnetzagentur 2014; Destatis 2017). Natural gas has two advantages as opposed to coal, Germany's other main fossil source of electricity: relatively low greenhouse gas emissions and high production flexibility. Gas-fired power plants can balance fluctuating wind and solar in-feed in the absence of affordable storage technologies or demand side management. Some experts hence call for keeping stable or even increasing gas-fired generation as a part of the energy mix at least in the mid-term (Graichen and Redl 2014).

This paper shows that existing academic models fail to adequately model the competitiveness of gas-fired power plants in markets with low power prices. By modelling only daily and not hourly operating decisions and by neglecting ramping times and costs, these models on the one hand under- and on the other hand over-estimate the value of gas-fired generation.

Using a real options model, this paper better quantifies a gas-fired power plant's operating value as well as the value of an investment in a new plant against the background of an energy market in transition to renewable energies. The model is run with recent data for Germany's power sector and for different types of gas-fired power plants.

The goal of this paper is twofold. First, the paper achieves a more realistic value by improving on existing option models in several ways: it models electricity and gas prices as a two-dimensional stochastic process, each component consisting of the sum of a seasonal pattern and a mean-reverting process; it uses higher granularity by modelling hourly time-steps; and it incorporates power plant ramping times and costs. Second, it compares two types of power plant models, one with daily and one with hourly operating decisions, and quantifies the value of a plant's intraday flexibility. The hourly model replicates operators' and investors' decision making accurately. This is evidenced by the fact that the results trace current major developments like the recent decline and come-back of gas-fired power in Germany.

The paper contributes to a better understanding of the choices operators and investors face in current electricity markets. In the absence of large scale storage solutions flexible supply of electricity, as provided by gas, is important in the transition to renewable energies in Germany and across Europe.

The paper uniquely focuses on electricity spot markets and, for simplicity, abstracts away from interactions with ancillary services. Ancillary services consist of a variety of operations beyond generation and transmission that are required to maintain grid stability and security. In light of an increase in intermittent renewable energy, this is an interesting area for further research outlined in the last section.

The paper is structured as follows. Section 2.2 gives an overview of the literature and defines the specific contribution of this paper. Section 2.3 lays out how electricity and gas prices are modelled. Section 2.4 explains the power plant model. Section 2.5 presents and discusses the results. Section

2.6 draws conclusions and section 2.7 gives ideas for further research and an outlook into the future of gas-fired generation in Germany.

2.2 Literature and contribution

2.2.1 From net present value to real option

Net present value (NPV) models are common in academia and practice to determine the profitability of investment decisions. While their simplicity is attractive, simplifying assumptions lead to problems: NPV models can only give yes-or-no investment advice, excluding the possibility to react strategically when risk resolves over time, thereby seriously undervaluing investment opportunities (Mei et al 2012). When using NPV approaches for valuing operating assets such as power plants, commodity prices have to be taken as deterministic and the operator has to fix an operating schedule beforehand without being able to react to changing prices. To counter this problem, NPV models are often used with several different price scenarios. Even though undervaluation can partly be alleviated in this way, the assignment of probabilities to different price paths remains arbitrary (Hsu 1998; Frayer and Uludere 2001).

Real option models take a different approach. Stewart Myers first coined the term *Real Option* in 1977 by applying option pricing theory to the valuation of non-financial growth opportunities (Myers 1977). In the late 1990s, we find first articles on the valuation of flexible power plants, where the operating decision of switching the plant on and off is depicted as a call option. The paper builds on this research.

Real options models explicitly estimate price trend and volatility from the data and thereby address arbitrariness. They give investors the possibility to alter their investment decision in light of evolving prices. In the case of operating assets such as power plants, operators are given the possibility to adapt production at specific points in time, that is by *exercising their real option* to produce and sell electricity. In this paper, the operator can decide – every day in the first model and every hour in the second - if the plant should buy gas in order to produce and sell electricity. The value of the power plant and thus its profitability is equal to the sum of call option values on the spread between electricity and gas prices over the plant's lifetime. To bring the model closer to reality, technical restrictions are also modelled, such as time and money spent to start and ramp up the plant.

While base load power plants, e.g. nuclear and coal, have to be operated pretty much throughout the year to be profitable, flexibility in production is very important for gas-fired power plants: as they ramp the fastest among all power plants and are often operated as *peakers*, that is only during some hours of the day, a large part of their value stems from price fluctuation and the operator's flexibility (Hsu 1998; Frayer and Uludere 2001; Fraser 2003; Fleten and Näsäkkälä 2009).

2.2.2 Option to operate in the literature

Table 2.1 provides an overview of the different model features in the literature. Features that were judged decisive for the choice of the modelling techniques used here are marked in green in the table.

Table 2.1: Option models of operating assets in the literature (MR = Mean Reversion, GBM = Geometric Brownian Motion, SDP = Stochastic Dynamic Programming, BS = Black and Scholes, MC = Monte Carlo).

Reference	Exchange option	Ramping restrictions	Model	Method	Application
Hsu 1998	Yes	No	GBM	Adjusted BS	Gas plant in US
Gardner, Zhuang 2000	No	Yes	MR	SDP	Hypothetical power plant
Tseng, Barz 2000	Yes	Yes	MR	MC, SDP	Hypothetical gas-fired plant
Deng et al 2001	Yes	No	GBM	Adjusted BS	Four gas-fired plants in California
Frayer, Uludere 2001	Yes	No	GBM	Adjusted BS	Gas- and coal-fired plants in US
Deng, Oren 2003	Yes	Yes	MR	Quadrinomial, SDP	Hypothetical gas-fired plant
Denton et al 2003	No	Yes	MR	Trinomial	n/a
Hahn, Dyer 2007	Yes	No	MR	Quadrinomial	Hypothetical gas/oil switching option
Tseng, Lin 2007	Yes	No	MR	Trinomial, SDP	Hypothetical gas-fired plant
Fleten, Näsäkkälä 2009	Yes	No	MR	Analytical, numerical	Gas-fired plant in Scandinavia
Hach, Spinler 2014	Yes	No	GBM	Quadrinomial	Combined cycle gas-fired plant in Germany
This paper	Yes	Yes	MR	Quadrinomial, SDP	Several different German gas-fired plants

This paper innovates on the existing real options literature by combining the following features:

1. The option is modelled as an **exchange option with two correlated underlyings** as opposed to one. If only electricity and not gas is modelled stochastically, the plant is likely to be over-

valued if one fixes the gas price too low, or undervalued if too high. Papers that used two underlyings are marked green in table 2.1.

2. It is generally assumed that **commodity prices are mean-reverting (MR)** rather than following a Geometric Brownian Motion. The logic behind this assumption is that if a commodity increases in price, new suppliers are attracted to the market. They increase supply, which will lower the price until it eventually equals its long-term mean again, the marginal cost of production. Papers that used mean-reverting prices are marked green in table 2.1.

3. This paper marries option model research with another body of literature dedicated to the estimation of commodity spot prices (e.g. Keles et al 2012; Paraschiv et al 2015). It depicts electricity and gas prices as a **two-dimensional stochastic process, each component consisting of the sum of an Ornstein-Uhlenbeck mean-reverting process and a deterministic seasonal pattern**. The way prices are modelled is not listed in table 2.1: all authors use either only hypothetical price parameters to test their model, or they estimate parameters from historical prices in a simplistic way without accounting for seasonalities.

4. **Ramping restrictions** are modelled. Ramping times and costs, e.g. the time and costs it takes to get a power plant from zero to full production, significantly lower the value of the option. Even though gas-fired power plants are ramping fast and cheaply compared to others, the results of this paper show how omitting ramping restrictions would nevertheless overvalue the plant significantly. Papers that used ramping restrictions are marked green in table 2.1.

5. **Hourly granularity** is modelled as opposed to daily or annual granularity implying that the operator can exercise the option every hour. As gas plant operators can maximise profits by adapting production on at least an hourly basis [1], this paper is more realistic than previous work. The granularity of the models is not listed in table 2.1: all papers either used daily or annual operating decisions. As section 2.5.4 will show, by modelling hourly granularity, profitability increases considerably as opposed to the daily model. It is therefore clearly necessary to model hourly operating decisions when analysing gas-fired power plants.

The paper's application is similar to Hach and Spinler (2014), who analyse a combined cycle gas-fired power plant in the current German energy market. Hach and Spinler approximate the investor's decision with two Geometric Brownian Motions for the prices, annual operating decisions and no restrictions regarding the ramping of the power plant. Their focus is on the option to invest, while this paper models the option to operate and derives the value of investing via the operating

[1] In addition to hourly contracts, in 2014 EPEX SPOT launched auctions for 15-minute contracts on the German intraday market (EPEX 2017).

profits. It combines the empirical approach and relevance of Hach and Spinler with a more detailed operating decision model relying on Hahn and Dyer (2007) and Deng and Oren (2003). Hahn and Dyer build a quadrinomial lattice of two correlated mean-reverting prices, which is used in this paper, and apply it to investments in gas and oil exploration. Deng and Oren derive an equivalent, but slightly less intuitive, quadrinomial model. On top of that, they build a power plant model using stochastic dynamic programming, which is able to depict ramping restrictions, and test it on a hypothetical plant. A similar power plant model depicting different existing German plants is used in this paper.

An advantage of modelling the operating decision as an option as in Deng and Oren (2003) and Hahn and Dyer (2007) is that capacity factors, i.e. how often the plant is run (see section 2.4.4), can be derived endogenously. The model can thereby be used, for example, in markets with different electricity price levels and varying shares of renewable energy. Capacity factors and profitability are affected via the observed electricity prices, without having to assume exogenous capacity factors driving the model, as in Hach and Spinler (2014).

2.3 Electricity and gas price model

Following the commodity price literature (e.g. Keles et al 2012; Paraschiv et al 2015), electricity and gas prices (S_t, P_t), are modelled as a two-dimensional stochastic process as described in equations 2.3.1 to 2.3.3. In accordance with the literature, electricity and gas prices are modelled separately as opposed to modelling only one single process $(S_t - P_t)$. This enables a more realistic depiction of seasonalities, which follow different cycles for electricity and for gas.

$$S_t = X_t + g_t, \qquad dX_t = \kappa_X(\mu_X - X_t)dt + \sigma_X \cdot dW_t \tag{2.3.1}$$

$$P_t = Y_t + h_t, \qquad dY_t = \kappa_Y(\mu_Y - Y_t)dt + \sigma_Y \cdot dB_t \tag{2.3.2}$$

$$dW_t dB_t = \rho dt \tag{2.3.3}$$

Each component is assumed to be the sum of a mean-reverting Ornstein-Uhlenbeck process $(\{X_t, Y_t; t \geqslant 0\})$ and a deterministic seasonal part (g_t, h_t). The seasonal parts are first estimated and removed from historical prices in section 2.3.3, thereby obtaining stochastic residue prices. Then, using these stochastic residues, the two-dimensional stochastic process is estimated in section 2.3.4 and modelled via a quadrinomial lattice in section 2.3.5. The estimated seasonal parts are then added back on to the modelled stochastic process in order to use these modelled electricity and gas prices with their respective probabilities in the power plant model in section 2.4.

A log-normal specification of the model was also tested, but did not create a sufficient fit. This is likely due to an increasing frequency of very low and even negative prices, which are allowed on the power exchange since 2008. Low or negative prices increasingly occur with the rise of renewables, since at times intermittent zero-marginal cost renewable sources like wind and sun produce at high levels and there are few profitable large-scale storage options available yet (Paraschiv et al 2014; Hirth 2018).

To test the log-normal specification, prices at or below zero have been transformed to the lowest positive value possible at the exchange, 0.01 €/MWh, in order to take the logarithm, following Keles et al (2012). As a high number of low prices occurred in the past few years, however, the distribution was unduly pulled to the left by the low values leading to bad fits. Hence this approach was deemed not suitable for recent electricity prices and the normally distributed model was used instead.

2.3.1 Model length, number of time steps and time step size

A quadrinomial lattice approach is used, based on Hahn and Dyer (2007). This lattice is essentially a three-dimensional binomial tree, which approaches the analytical option value by tracing the evolution of the two underlyings in discrete time. The model length[2] T is given by $T = n \cdot \triangle t$, with n being the number of time steps and $\triangle t$ the time step size.

$\triangle t$, T and n have to fulfil several conditions, as described in the following. First, we choose the time step size $\triangle t$. There are real world implications that influence our choice: to model a gas-fired power plant as an option, at least hourly time steps are desirable, because of the plant's high flexibility. In reality, operators maximise profits by running the plant only during peak electricity price hours. This feature has received little attention in previous work and mostly daily time steps have been modelled, as described in section 2.2.2. However, when both electricity and gas prices are modelled stochastically, one encounters the problem that, while for electricity even quarter-hourly prices exist, intraday *gas* prices are generally not liquid and daily prices have to be used instead. It therefore seems that only daily granularity is feasible, because there is no hourly gas price to match the hourly electricity price. For the estimation of seasonalities, it is acceptable to smooth the gas price over the day to create hourly prices; for the Ornstein-Uhlenbeck parameters in the price model, however, this is not possible, as it would lead to false volatility estimates.

To overcome this challenge, the paper follows a dual approach: seasonalities of the daily prices are estimated and removed (section 2.3.3), then the daily Ornstein-Uhlenbeck parameters are estimated (2.3.4), the stochastic parts of the daily prices are simulated (2.3.5) and the results are used

[2] We do not call T the *maturity*, but the *model length* or *time horizon for the analysis*, because the operator has the right to exercise the option at each time step.

in section 2.4 to run the daily power plant model. The results of the daily model (section 2.4.1.1) are not satisfactory, however, as they underestimate the value of gas-fired power as described earlier. The Ornstein-Uhlenbeck parameters estimated from the daily prices are therefore used in a power plant model with hourly granularity, too (2.4.1.2), whereas the seasonalities are estimated from hourly electricity prices and from daily gas prices smoothed over the day to increase the goodness of fit (2.3.3). As $\triangle t$ is expressed in terms of years ($\triangle t_{dailyModel} = \frac{1}{365}$, $\triangle t_{hourlyModel} = \frac{1}{8760}$), the same parameters received from section 2.3.4 and 2.3.5 can be used in both the daily and the hourly model.

Second, having set $\triangle t$ equal to one day and one hour for the daily and hourly models respectively, we now have to choose the model horizon T and, implied by that, the number of time steps modelled in one model run n. The goal of the analysis is to receive the operating margins (or later called operating values) and profits considering capital cost (or later called construction values) of different power plants over their whole lifetime. The lifetime of a power plant is estimated at 32 years following Schröder et al (2013). However, this does not imply that T necessarily has to equal 32 years. An alternative is to set T equal to a shorter time frame and sum up the results of the model runs in the end to receive the result over the whole lifetime.

In order to properly estimate the seasonal patterns of electricity and gas prices, however, T should equal at least one week, as electricity prices have strong weekly patterns with lower prices during the weekends.

Moreover, to be sure that the modelled option value approaches its analytical value and thereby closely tracks the historical price curves, n - and thereby also T - should be sufficiently large. At the same time, there is a trade-off of having a large n and T for two reasons: first, we want to keep computing time and memory use in a reasonable range. If we run, for example, the model over the whole life time of the plant, we would model $n = T/\triangle t = (32 \cdot 8,760h)/1h = 280,320$ time steps. In a quadrinomial lattice, even if the time steps themselves are modelled in several sections, a tree with at least $n^2 = 78 \cdot 10^9$ nodes for the branching of power and gas prices has to be built, which could potentially slow down calculations quite a bit. Second, the more decisive disadvantage of a big T is that one would assume constant mean and volatility parameters for electricity and gas prices over 32 years, which is not realistic. The smaller T, the better the model depicts changes in price behaviour partly due to, for example, increases in power from renewable energy.

After running several tests with artificially created price paths and ensuring accuracy, in the daily model, one month was set for T, i.e. $T_{hourlyModel} = n_{hourlyModel} \cdot \triangle t_{hourlyModel} = \frac{8760}{12} \cdot \frac{1}{8760} = \frac{1}{12}$ and $n_{hourlyModel} = \frac{8760}{12} = 730$.

In the daily model, with one month n would equal to only around $\frac{365}{12} \approx 30$, which proved to be insufficient to approximate the analytical value of the option. Half a year is therefore modelled at a time, i.e. $T_{dailyModel} = n_{dailyModel} \cdot \triangle t_{dailyModel} = \frac{365}{2} \cdot \frac{1}{365} = \frac{1}{2}$, and $n_{dailyModel} = \frac{365}{2} = 182.5$, i.e. either 182 or 183, for January 1 to June 30 and July 1 to December 31. This is sufficient to obtain a correct option value and at the same time keep the time frame short enough to model changes in the price parameters.

2.3.2 Price data

For electricity prices, we use the Phelix (*Physical Electricity Index*) day-ahead auction price, which is based on a daily auction of electricity for delivery the following day in 24-hour intervals. In the hourly model, the hourly base load price is used, i.e. the average auction price for each hour. In the daily model, the Phelix Day Base is used, i.e. an average over the hourly base load prices (EPEX 2017). The Phelix is the most widely used electricity price in the German market area, determining prices also on forward markets (Interview A 2016).

For gas prices, daily settlement prices of NetConnect Germany (NCG), which covers the biggest German market area, are used. They are calculated by taking the average of the trades closed from 5:15 to 5:30 pm on the trading day preceding the delivery day (EEX 2014). This price is chosen for two reasons. First, whereas hourly prices often rely on only few or no trades at all, trading of daily settlement prices is more liquid and therefore often used by utilities in their gas purchasing contracts (Interview B 2016). Second, the European Energy Exchange (EEX) started publishing settlement prices in 2007, which makes for a relatively long history compared to, for example, daily reference prices, which are only available from 2011 (EEX 2017).

2.3.3 Removing seasonalities

Seasonalities are removed in several steps, relying partly on Keles et al (2012) (see equations 2.3.4, 2.3.5, 2.3.6 and 2.3.7). The goal is to receive the stochastic residues by subtracting various seasonal patterns. The seasonalities are estimated and removed in the order in which they appear below. Appendix 2.9.1 contains the equations for the estimations of all seasonalities. Building on the model by Keles et al, different other specifications and orders of estimation were tested but they resulted in lower fits.

Daily model

$$X_t = S_t - \text{Trend}_{S_t} - \text{MonthlyMeans}_{S_t} - \text{WeeklyAndOtherCyclesDaily}_{S_t} \tag{2.3.4}$$

$$Y_t = P_t - \text{Trend}_{P_t} - \text{MonthlyMeans}_{P_t} - \text{WeeklyAndOtherCyclesDaily}_{S_t} \tag{2.3.5}$$

Hourly model

$$X_t = S_t - \text{Trend}_{S_t} - \text{DailyMeans}_{S_t} - \text{WeeklyAndOtherCyclesHourly}_{S_t} \tag{2.3.6}$$

$$Y_t = P_t - \text{Trend}_{P_t} - \text{DailyMeans}_{P_t} - \text{WeeklyAndOtherCyclesHourly}_{S_t} \tag{2.3.7}$$

2.3.4 Parameter estimation of stochastic price parts

After having obtained X_t and Y_t by estimating and subtracting the seasonalities as described above, the Ornstein-Uhlenbeck parameters $\mu_X, \mu_Y, \sigma_X, \sigma_Y, \kappa_X, \kappa_Y$ and ρ can be estimated. They are obtained by multivariate Maximum Likelihood:

$$ln(L) = -N \cdot ln(2\pi) - ln(|\Sigma|) - \frac{1}{2}\sum_{i=1}^{N}(X_i - \mu)^T \Sigma^{-1}(X_i - \mu) \tag{2.3.8}$$

whereas

$$N = n_{dailyModel}, \qquad X = \begin{pmatrix} X_t \\ Y_t \end{pmatrix}, \qquad \mu = \begin{pmatrix} \mu_X \\ \mu_Y \end{pmatrix}, \qquad \Sigma = \begin{pmatrix} \Sigma_{XX} & \Sigma_{XY} \\ \Sigma_{YX} & \Sigma_{YY} \end{pmatrix} \tag{2.3.9}$$

The results of the parameter estimation and the goodness of fit measures are reported in appendices 2.9.2 and 2.9.3. The results for κ_X and κ_Y imply a half life of the two-dimensional stochastic process of 15 hours on average. Apart from the greater profitability obtained as results of the power plant model (see section 2.5.4), this is another indication that the hourly model is more suited than the daily one. Figure 2.3.1 shows the historical and simulated daily prices.

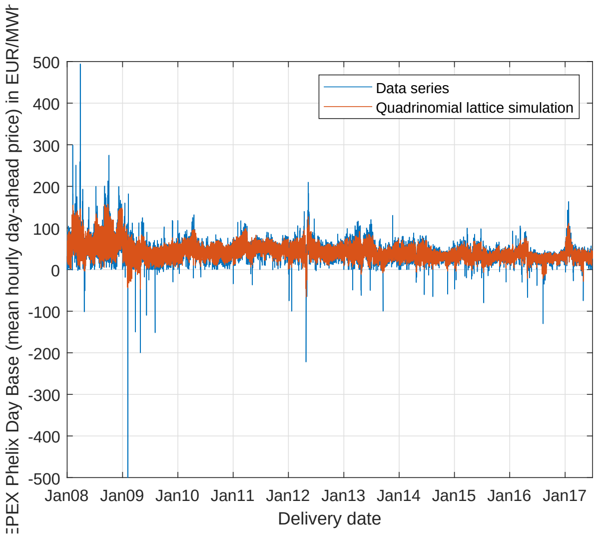
2.3.5 Building the quadrinomial lattice

To model the stochastic part X_t and Y_t of the prices, a quadrinomial lattice approach is chosen, following Hahn and Dyer (2007). X_t and Y_t are approximated by a quadrinomial sequence of n periods of length $\triangle t$, with T being the time horizon for the analysis, $T = n \cdot \triangle t$, and

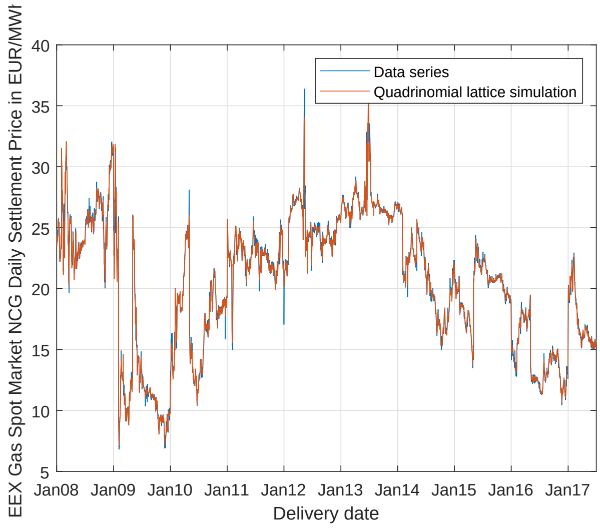
$$X_{t+1}^{up} = X_t + u_X, \qquad X_{t+1}^{down} = X_t - u_X \tag{2.3.10}$$

$$Y_{t+1}^{up} = Y_t + u_Y, \qquad Y_{t+1}^{down} = Y_t - u_X \tag{2.3.11}$$

The size of the increments of the price movements u_X and u_Y and their probabilities for each



(a) Historical daily electricity spot price and model simulation



(b) Historical daily gas spot price and model simulation

Figure 2.3.1: Electricity and gas prices in Germany 2008-2017. Source: EPEX 2017 and EEX 2017.

branch are given by

$$u_X = \sqrt{\Delta t} \cdot \sigma_X, \qquad u_Y = \sqrt{\Delta t} \cdot \sigma_Y \tag{2.3.12}$$

$$p(X_{up}, Y_{up}) = \frac{u_X u_Y + u_Y \kappa_X (\mu_X - X_t)\Delta t + u_X \kappa_Y (\mu_Y - Y_t)\Delta t + \rho \sigma_X \sigma_Y \Delta t}{4 u_X u_Y} \tag{2.3.13}$$

$$p(X_{up}, Y_{down}) = \frac{u_X u_Y + u_Y \kappa_X (\mu_X - X_t)\Delta t - u_X \kappa_Y (\mu_Y - Y_t)\Delta t - \rho \sigma_X \sigma_Y \Delta t}{4 u_X u_Y} \tag{2.3.14}$$

$$p(X_{down}, Y_{up}) = \frac{u_X u_Y - u_Y \kappa_X (\mu_X - X_t)\Delta t + u_X \kappa_Y (\mu_Y - Y_t)\Delta t - \rho \sigma_X \sigma_Y \Delta t}{4 u_X u_Y} \tag{2.3.15}$$

$$p(X_{down}, Y_{down}) = \frac{u_X u_Y - u_Y \kappa_X (\mu_X - X_t)\Delta t - u_X \kappa_Y (\mu_Y - Y_t)\Delta t + \rho \sigma_X \sigma_Y \Delta t}{4 u_X u_Y} \tag{2.3.16}$$

If at any node, any of these four probabilities result in a value smaller than zero or greater than one, they have to be censored to zero or one respectively. All four probabilities have to add up to one at each node. However, one cannot simply define $p(X_{up})$ and infer $p(X_{down}) = 1 - p(X_{up})$ as in the case in a binomial tree with just one stochastic process and two probabilities. To solve this problem, conditional probabilities are calculated and used to infer the unconditional probabilities. It holds from Bayes' Rule that

$$p(X_{up}, Y_{up}) = p(Y_{up}|X_{up}) \cdot p(X_{up}) \qquad \rightarrow \qquad p(Y_{up}|X_{up}) = \frac{p(X_{up}, Y_{up})}{p(X_{up})} \tag{2.3.17}$$

The marginal probabilities of X_t are given by

$$p(X_{up}) = \frac{1}{2} + \frac{1}{2}\frac{\kappa_X(\mu_X - X_t)}{u_X}, \qquad p(X_{down}) = \frac{1}{2} - \frac{1}{2}\frac{\kappa_X(\mu_X - X_t)}{u_X} \tag{2.3.18}$$

The conditional probabilities of Y_t, of which only two exist per node, can therefore be calculated and directly censored to one:

$$p(Y_{up}|X_{up}) = \max[0, \min(1, \frac{p(X_{up}, Y_{up})}{p(X_{up})})] \tag{2.3.19}$$

$$p(Y_{down}|X_{up}) = 1 - p(Y_{up}|X_{up}) \tag{2.3.20}$$

$$p(Y_{up}|X_{down}) = \max[0, \min(1, \frac{p(X_{down}, Y_{up})}{p(X_{down})})] \tag{2.3.21}$$

$$p(Y_{down}|X_{down}) = 1 - p(Y_{up}|X_{down}) \tag{2.3.22}$$

The conditional probabilities are then used to calculate the correctly censored marginal probabilities:

$$p(X_{up}, Y_{up}) = p(Y_{up}|X_{up}) \cdot p(X_{up}) \tag{2.3.23}$$

$$p(X_{up}, Y_{down}) = p(Y_{down}|X_{up}) \cdot p(X_{up}) \tag{2.3.24}$$

$$p(X_{down}, Y_{up}) = p(Y_{up}|X_{down}) \cdot p(X_{down}) \tag{2.3.25}$$

$$p(X_{down}, Y_{down}) = p(Y_{down}|X_{down}) \cdot p(X_{down}) \tag{2.3.26}$$

2.4 Power plant model

The power plant model is adapted from Deng and Oren (2003). One advantage of Deng and Oren's approach is that the operating capacity, i.e. how much electricity is produced by the power plant, is not fixed exogenously as in Hach and Spinler (2014), but is determined endogenously as operating profit is maximised.

Another advantage is that rather than assuming that ramping and switching off the plant occurs immediately and at no cost, as in most research so far, start-up and ramping times as well as costs are modelled. While the authors depict a hypothetical power plant to test their model, here different power plant types that come close to the current German plants are modelled. Appendix 2.9.5 contains values, units and sources of the different cost items.

Seven different types of power plants are modelled in the daily, and eight in the hourly model: two combustion (or gas) turbines (type 5, 6), two steam turbines (type 7, 8) - both are also called *open cycle* gas turbines (OCGT) -, two combined cycle gas turbines (CCGT) (type 3, 4), a hypothetical plant that does not incur any of the described costs and ramps like a CCGT plant (type 2, only in the hourly model) and a hypothetical plant without costs and immediate ramping (type 1). Gas turbines are more flexible than steam turbines. CCGTs combine both turbine types, steam and combustion, in a sequential cycle, and thereby increase overall efficiency; the ramping time, however, is also longer than in a pure gas turbine (Schröder et al 2013). For each of the real existing plant types an efficient and an inefficient plant are modelled. The heat rate values are taken from a database of German power plants. For efficient plants the average efficiencies of gas-fired power plants built after 2010 are used; for inefficient ones the average efficiency until 2010 (Open Power Systems Data 2017). For the hypothetical plants one assumes the characteristics of an efficient CCGT.

Start-up time restrictions result from the need to synchronize the generator to the grid frequency and from the thermal stress through temperature and pressure differences. Start-up costs (c_{start}) occur due to the start-up fuel needed. Ramping costs (c_{ramp}) imply fuel, capital and maintenance cost. Fixed cost (c_{fix}), variable cost (c_{var}), CO_2-cost (c_{CO2}) and the efficiency of the plant (expressed as heat rate Hr, the multiplicative inverse of efficiency) are also considered.

The plant runs more efficiently - with a low heat rate Hr_{min} - when it produces at maximum capacity Q_{max} and less efficiently - with a high heat rate Hr_{max} - when it produces at minimum capacity Q_{min}. The minimum capacity is chosen as the minimum load level below which a stable operation is not possible due to insufficient temperature or excessive emissions (Schröder et al 2013). The model only uses these three levels of capacity - off, minimum and maximum - even though in reality, an infinite number of different capacity levels are possible. The model has also been tested for three different capacity levels - zero, minimum, medium and maximum. For the two gas turbines (type 5, 6), the difference is negligible with an average difference of $4.7 \cdot 10^{-5}$% in the monthly operating value. The difference is defined as $\triangle OV = \frac{OV_{2levels} - OV_{3levels}}{|OV_{2levels}|}$.

For the other plant types (CCGT and steam - type 3, 4, 7, 8), due to the discreteness of the model, more capacity levels would imply an unrealistically long ramping time of two hours. This leads to a situation, where more modelled capacity levels would actually lead to lower operating values. The average difference is 8.03%. This indicates that the model specification with zero, minimum and maximum capacity is in our case both sufficient and more suited to modelling gas turbines as well as CCGT and steam turbines.

As a discount rate, a single estimate of the energy sector's cost of capital of 7.2% (KPMG 2014) has been used for simplicity. A sensitivity analysis is performed in section 2.5.5.

2.4.1 Operating profit

$R_t(a_t, S_t, P_t, w)$ depicts the operating profit of the power plant, with electricity and gas prices S_t, P_t. The states of the power plant are either off ($w_t = 1$) or on ($w_t = 2$). In each state, the power plant operator can choose between the actions of switching off the power plant ($a_t = a_I$), go to low capacity ($a_t = a_{\mathrm{II}}$), or to full capacity ($a_t = a_{\mathrm{III}}$).

For the hypothetical plant with immediate ramping and no costs (type 1), a simpler model is used where the states of the power plant are not distinguished and the operator can decide at each time step to run the plant at zero ($a_t = a_{\mathrm{I}}$), low ($a_t = a_{\mathrm{II}}$) or full ($a_t = a_{\mathrm{III}}$) capacity. Equations for all power plant models can be found in appendix 2.9.4.

2.4.1.1 Daily model

In the daily model, one time step corresponds to one day. As gas-fired power plants can be ramped to full capacity within few hours or even minutes, the power plant is modelled as being able to be ramped to the low state ($a_t = a_{II}, w_t = 1$) and the full state immediately ($a_t = a_{III}, w_t = 1$).

2.4.1.2 Hourly model

In the hourly version, one time step corresponds to one hour, which allows for more realistic modelling. As gas turbines (type 5, 6) ramp within minutes, we again assume that they can reach low ($a_t = a_{III}, w_t = 3$) and full capacity ($a_t = a_{III}, w_t = 3$) immediately.

The second hypothetical plant (type 2), CCGTs (type 3, 4) and steam turbines (type 7, 8), however, reach full capacity only after around one hour (Schröder et al 2013). In these models, the states of the power plant are either off ($w_t = 1$), low ($w_t = 2$) or full ($w_t = 3$). In each state, the power plant operator can choose between the actions of switching off the power plant ($a_t = a_I$), stay in the current state ($a_t = a_{\mathrm{II}}$), or (try to) ramp up the power plant ($a_t = a_{\mathrm{III}}$). If the plant already is in full state ($w_t = 3$), both actions $a_t = a_{\mathrm{II}}$ and $a_t = a_{\mathrm{III}}$ imply staying in the current state.

2.4.2 Operating value

The operating value V_t, i.e. the value of the operating decisions not considering capital cost, is modelled as the sum of the expected profit in each period when choosing the most profitable action a_t. V_0 is thus calculated using stochastic dynamic programming with backwards induction, based on the model by Deng and Oren (2003).

$$V_t(S_t,P_t,1) = \max_{a_t} \begin{cases} R(a_I,S_t,P_t,1)+e^{-r\cdot\triangle t}\cdot E_t[V_{t+1}(S_{t+1},P_{t+1})] & \text{if } a_t = a_I \\ R(a_{II},S_t,P_t,1)+e^{-r\cdot\triangle t}\cdot E_t[V_{t+1}(S_{t+1},P_{t+1})] & \text{if } a_t = a_{II} \\ R(a_{III},S_t,P_t,1)+e^{-r\cdot\triangle t}\cdot E_t[V_{t+1}(S_{t+1},P_{t+1})] & \text{if } a_t = a_{III} \end{cases} \forall S_t,P_t,w_t=1 \tag{2.4.1}$$

$$V_t(S_t,P_t,2) = \max_{a_t} \begin{cases} R(a_I,S_t,P_t,2)+e^{-r\cdot\triangle t}\cdot E_t[V_{t+1}(S_{t+1},P_{t+1})] & \text{if } a_t = a_I \\ R(a_{II},S_t,P_t,2)+e^{-r\cdot\triangle t}\cdot E_t[V_{t+1}(S_{t+1},P_{t+1})] & \text{if } a_t = a_{II} \\ R(a_{III},S_t,P_t,2)+e^{-r\cdot\triangle t}\cdot E_t[V_{t+1}(S_{t+1},P_{t+1})] & \text{if } a_t = a_{III} \end{cases} \forall S_t,P_t,w_t=2 \tag{2.4.2}$$

$$V_t(S_t,P_t,3) = \max_{a_t} \begin{cases} R(a_I,S_t,P_t,3)+e^{-r\cdot\triangle t}\cdot E_t[V_{t+1}(S_{X_t t+1},P_{t+1})] & \text{if } a_t = a_I \\ R(a_{II},S_t,P_t,3)+e^{-r\cdot\triangle t}\cdot E_t[V_{t+1}(S_{t+1},P_{t+1})] & \text{if } a_t = a_{II} \\ R(a_{III},S_t,P_t,3)+e^{-r\cdot\triangle t}\cdot E_t[V_{t+1}(S_{t+1},P_{t+1})] & \text{if } a_t = a_{III} \end{cases} \forall S_t,P_t,w_t=3 \tag{2.4.3}$$

In order to make the operating profits at each time step in the daily and the ones in the hourly model comparable, one can calculate the monthly discounted operating profit for the daily model as follows:

$$V_0^{monthly} = \frac{1}{6}\cdot V_0^{semiannual}\cdot e^{5r\cdot\triangle t} \tag{2.4.4}$$

with $\triangle t$ equal to one month expressed in years, i.e. $\frac{1}{12}$.

The operating value over the whole time frame, i.e. from January 2008 to end of June 2017, is calculated by taking the present value of all profits over the whole modelling period:

$$V_{2008-2017}^{daily} = \sum_{k=1}^{K}(e^{\frac{-r}{2}\cdot k}\cdot V_{0,k}) \tag{2.4.5}$$

$$V_{2008-2017}^{hourly} = \sum_{k=1}^{K}(e^{\frac{-r}{12}\cdot k}\cdot V_{0,k}) \tag{2.4.6}$$

whereas $k = 1$ stands for the first half year modelled (daily model) or the first month (hourly model) and K for the last. I.e. $V_{0,1}$ is the operating value of the first half of 2008 (daily) or of January 2008 (hourly), discounted to the first day of 2008, $V_{0,2}$ is the operating value of the second half of 2008 (daily) or of February 2008 (hourly), discounted to the first of February and the first of July respectively, etc. Accordingly K stands for the first half of 2017 (daily model) or June 2017 (hourly model) discounted to the first day of 2017 and to first of June respectively.

2.4.3 Construction value

Subsequently, the construction value of the power plant for each modelling horizon, i.e. the value of the generation investment incorporating capital cost I, is calculated as the discounted sum of operating profits over the plant's lifetime minus the investment cost. It is assumed that the same operating profit is continuously obtained over the plant's lifetime. The lifetime of the power plant is estimated at 32 years (Schröder et al 2013).

$$\text{Construction value}_k^{daily} = \sum_{t=0}^{2\cdot 32} (e^{\frac{-r}{2}\cdot t} \cdot V_{0,k}) - I \tag{2.4.7}$$

$$\text{Construction value}_k^{hourly} = \sum_{t=0}^{12\cdot 32} (e^{\frac{-r}{12}\cdot t} \cdot V_{0,k}) - I \tag{2.4.8}$$

whereas k stands for each model horizon of half a year (daily model) or one month (hourly model). The assumption that the operating profit is stable 32 years into the future is of course unrealistic. However, modelling changes in the operating value would require building an hourly price forward curve base on the forward prices known at each time step. This would add another layer of complexity to the model and is therefore left for future papers (see also section 2.7). In the absence of a forward price model, the construction value here can be interpreted as a rough indication of overall profitability at the time of construction without taking expected future price changes into account. In addition to that, section 2.5.4 derives an estimation of the cumulative historically realised operating margins from 2017 to 2008.

2.4.4 Capacity factor

The modelling of the operating decision as an option makes it possible to derive the capacity factor endogenously. The capacity factor, sometimes also called load factor, is the percentage of a power plant's capacity being used over a certain time frame. It is calculated by dividing the total number of MWh electricity produced by the maximally possible producible number. The result is a value between 0 and 1. While gas-fired power plants are often employed as *peakers*, i.e. only run during the hours of the day when electricity prices peak, capacity factors below 20% usually lead to low - or even negative - profits, if fixed costs cannot be covered.

$$\text{Capacity factor} = \frac{\sum_{t=1}^{T} Q_t}{Q_{max} \cdot T} \tag{2.4.9}$$

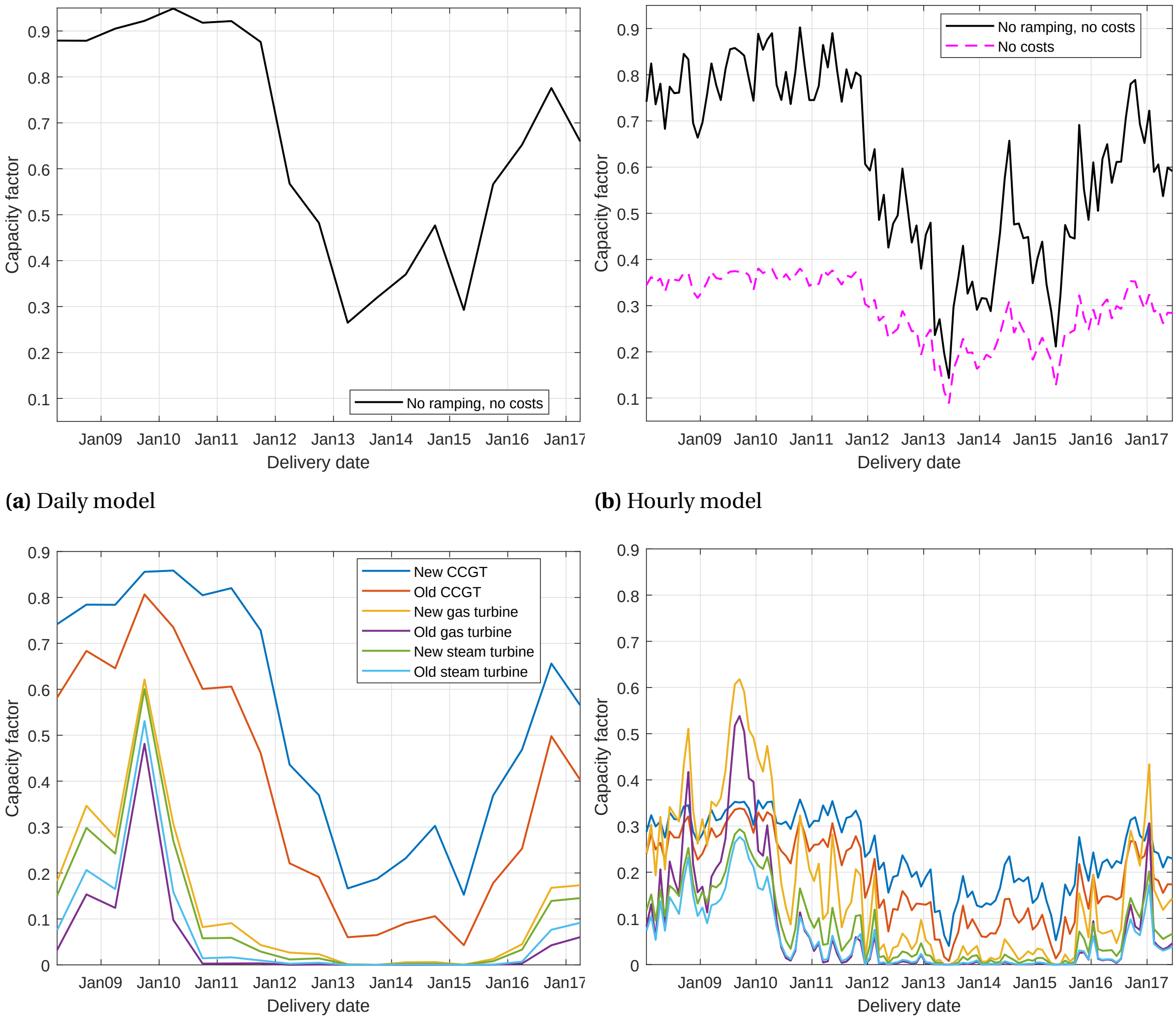
with

$$Q_t = \underset{Q \in [0, Q_{min}, Q_{max}]}{\arg\max} V_t \tag{2.4.10}$$

2.5 Results

2.5.1 Capacity factor

All models and power plant types show a decrease in usage of gas-fired power from mid-2012 at the latest, a period of very low or even zero capacity factors and then an increase from mid-2015, pointing at the decline of gas prices and the recovery of electricity prices as discussed in the introduction.



(a) Daily model

(b) Hourly model

(c) Daily model

(d) Hourly model

Figure 2.5.1: Capacity factor for each period of simulation

For the hypothetical plants with no costs modelled except for gas, the capacity factors range between 9 and 95 % (figure 2.5.1a and 2.5.1b). In the hourly model, the power plant with one hour ramping time displays considerably lower capacity factors as opposed to the plant with immediate generation, at times by some 50 percentage points.

As to be expected, for the existing power plants, capacity factors are at all times lower than for the respective plants without ramping and costs (figure 2.5.1c and 2.5.1d). In the daily model, new and old CCGT plants display clearly higher capacity factors than all other plants. This picture changes when looking at the hourly model: as CCGT plants ramp slower than gas turbines, which can only be properly modelled with hourly time steps, the latter overtake CCGT plants in terms of their capacity factor during some months between 2008 and 2010 and again in December 2016 and January 2017. CCGT and steam plants show a smaller range of capacity factors than gas turbines: as they loose time ramping up, they cannot exploit peaks in price spreads to the extent that gas turbines can. In general, all plants tend to increase their load from mid-2015 when electricity prices recover and gas prices decline.

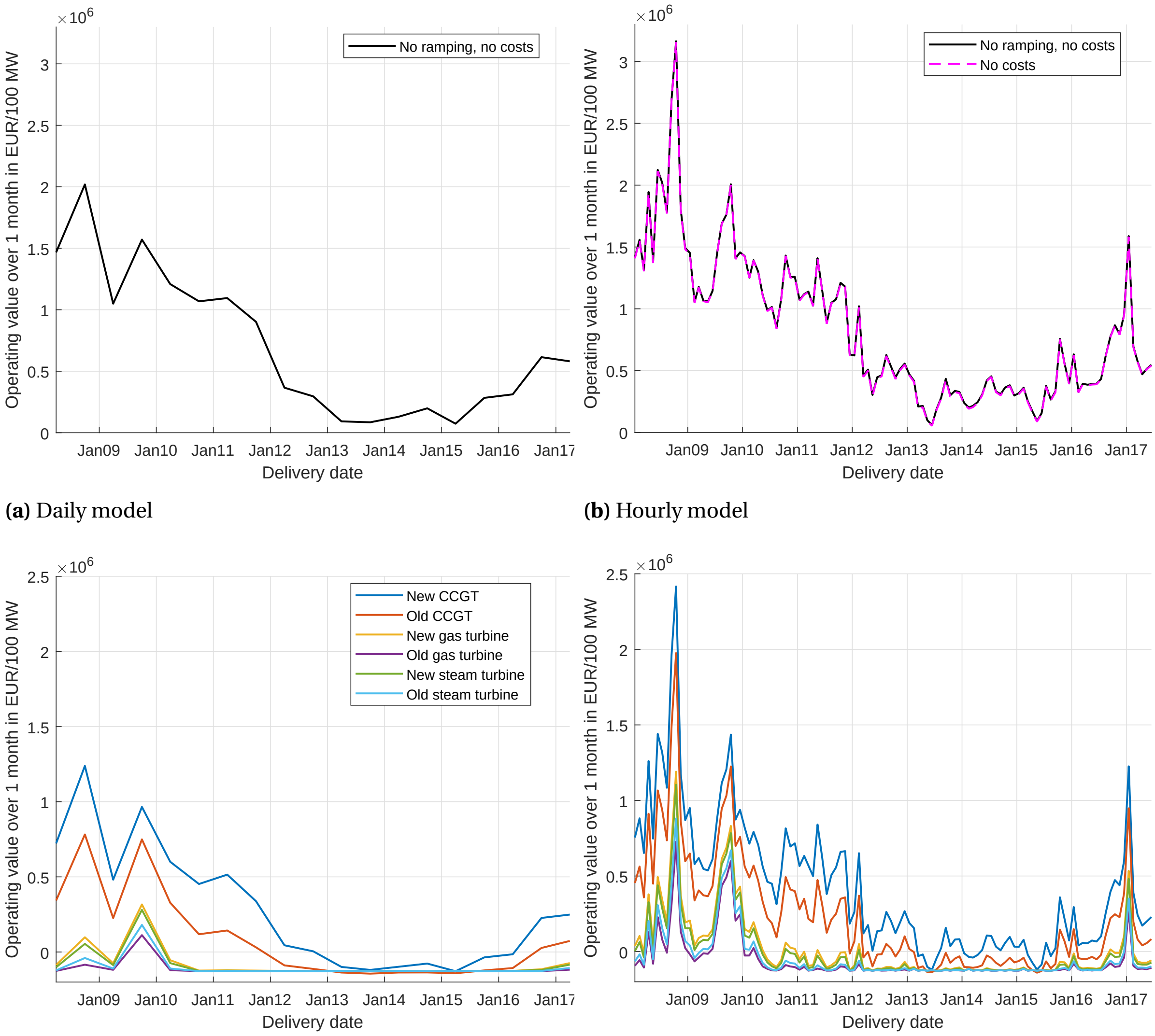
It is noticeable that in the hourly model all power plants display very low capacity factors, mostly smaller than 20% during the period from 2012 to 2015. While low capacity factors are common for power plants used only during peak hours, as gas plants often are, numbers below 30% point at low profitability (Hach and Spinler 2014). This low profitability becomes evident when analysing the operating value in the next section.

2.5.2 Operating value

Operating values give an idea of the operating margins over a certain time frame without considering any capital costs for building the plant. Daily (figure 2.5.2a and 2.5.2c) and hourly (fig. 2.5.2b and 2.5.2d) operating values have roughly similar shapes. But as operators profit more from higher spreads by ramping up production only in peak hours, hourly results are generally higher and display higher peaks.

While operating values of the power plants without costs are always positive (figure 2.5.2a and 2.5.2b), real world power plants were facing tougher times. In the daily model (figure 2.5.2c), all plants operate at a loss from 2013 to 2016. The flat lines indicate that power plants are operated at (almost) zero capacity, which means that (negative) operating profits reflect the incurred fixed costs. In the hourly model (figure 2.5.2d), CCGT plants are partly in the money during that time. Profits tend to increase from mid-2015 and in December 2016 and January 2017, all power plants show a positive peak in the hourly model due to a jump in hourly electricity prices to over 160 EUR/MW (figure 2.5.3). In the daily model, on the other hand, only CCGT plants operate at a - lower - profit from mid-2016.

Interestingly, while ramping times played a major role for the capacity factors, when looking at profitability, their importance vanishes. The hypothetical plant with one hour ramping and no



(a) Daily model

(b) Hourly model

(c) Daily model

(d) Hourly model

Figure 2.5.2: Operating value over 1 month in EUR/100MW

costs generates almost as high profits as the one with immediate ramping and no costs (figure 2.5.2b). This is also evident in figure 2.5.2d: in spite of their slower ramping times, CCGT plants are, thanks to their high efficiency, always more profitable than all other plants. The reason might be that the additional hours during which a faster plant can be profitably operated contribute only little to the overall profit because they exhibit low spreads between electricity and gas price.

For the whole modelling exercise this indicates that the granularity of the model is probably sufficient to model profits and there is no need to model time steps of, say, quarters of an hour. Moreover, the very low capacity values that are observed in the hourly model (figure 2.5.2c) might be an under-estimation. Smaller time steps are likely to lead to higher capacity factors, even if profits would hardly change.

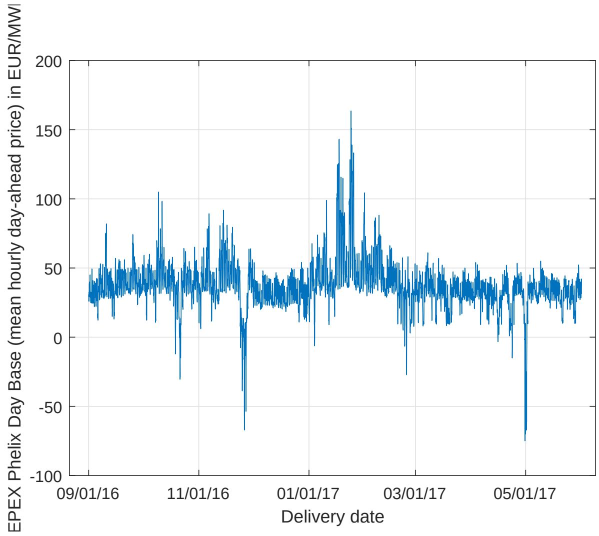


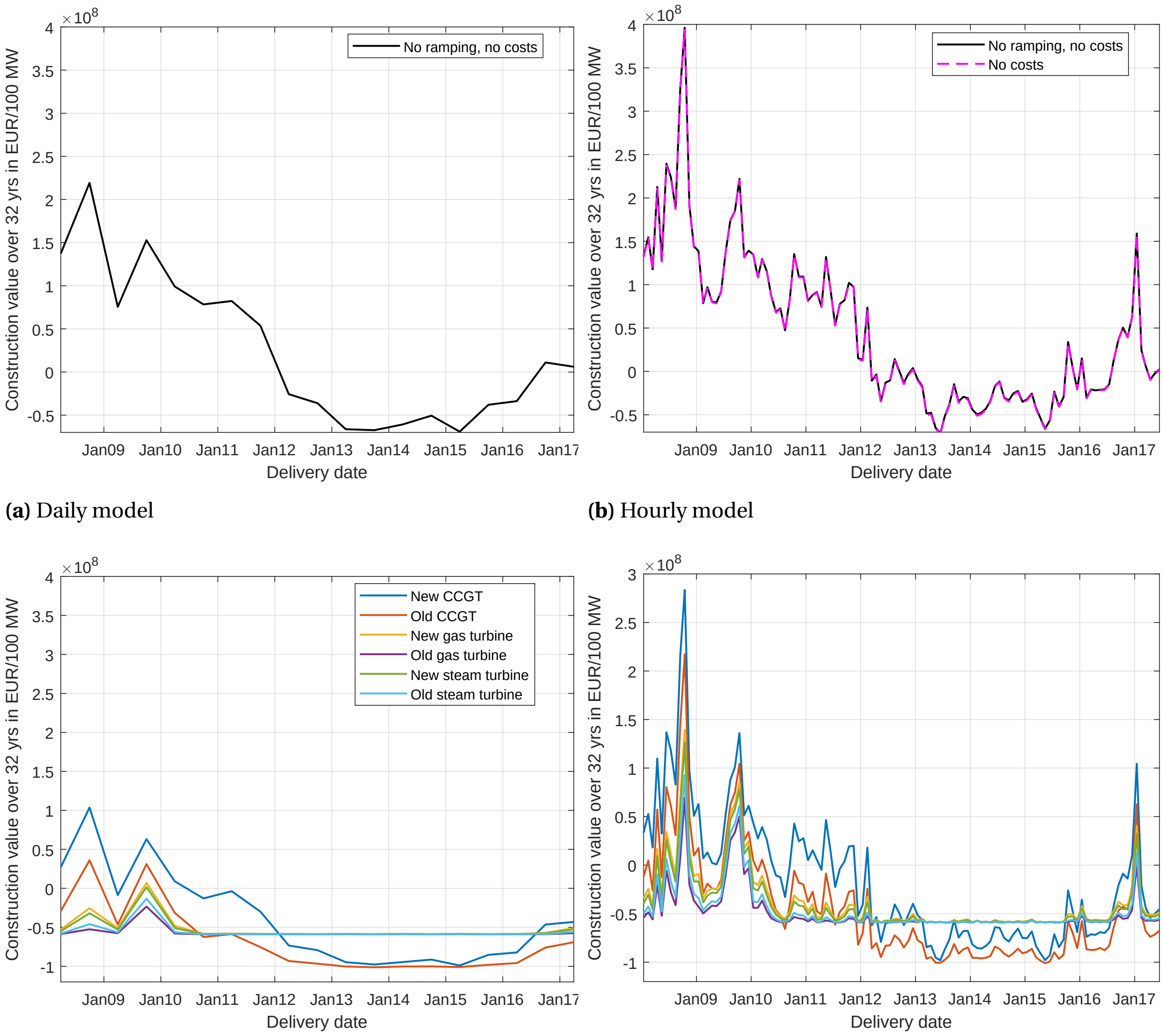
Figure 2.5.3: Historical hourly electricity spot price, showing a peak in December 2016 and January 2017

2.5.3 Construction value

By taking the sum of discounted operating profits over the average lifetime of 32 years, the construction values are obtained. These are a rough indication of profitability including capital cost over the whole lifetime without taking any future price changes into account. In accordance with the hypothetical operating values, hypothetical construction values of the daily and the hourly model show roughly similar shapes. Again, the daily results (figure 2.5.4a and 2.5.4c) are clearly lower than in the hourly model (2.5.4b and 2.5.4d) and ramping times do not seem to play a big role (2.5.4b).

Looking at figure 2.5.4c and 2.5.4d, the higher granularity of the hourly model produces one key difference: in the daily model from mid-2010 on, all types of plants display negative construction values, i.e. there is no incentive for construction of a new plant. In the hourly model, between 2010 and 2011, at least new CCGT plants have positive values at times, and again in January 2017, during the peak month mentioned earlier, all plants are worthwhile being built again.

When we compare these results with the evolution of gas-fired capacity outlined in the introduction, figure 2.5.4d shows strong similarities, but fails to completely account for the recent rise in capacity. Some reasons for this are discussed in section 2.6.



(a) Daily model

(b) Hourly model

(c) Daily model

(d) Hourly model

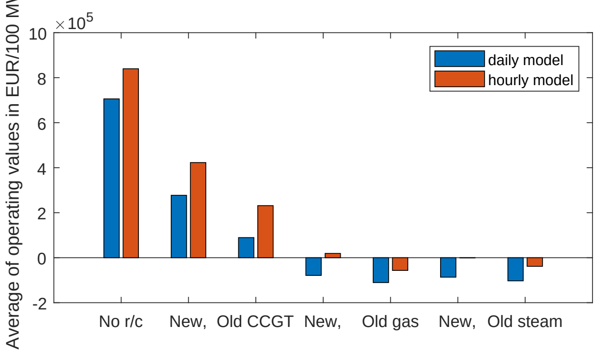
Figure 2.5.4: Construction value over 32 years in EUR/100 MW

2.5.4 Comparison of daily and hourly model over the whole modelling horizon

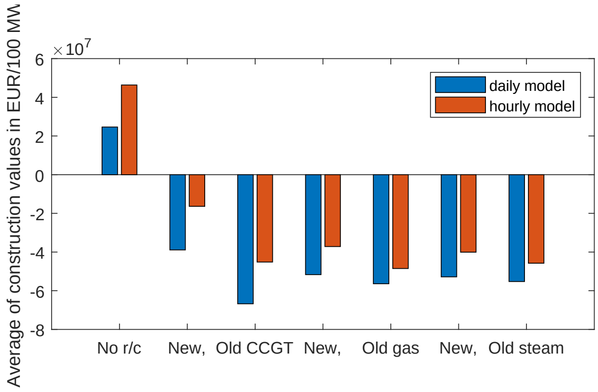
By analysing some key figures of the daily and hourly model over the whole modelling horizon, that is from January 2008 to June 2017, we can confirm, visualise and further analyse the conclusions of the previous sections.

Figures 2.5.5a, 2.5.5b and 2.5.5dshow the averages of the capacity factors and the operating and construction values for each month that were plotted in the previous sections. As explained earlier, the construction values do not incorporate expected future price changes. Figure 2.5.5c presents the NPV of the sum of all operating values from 2008 to 2017. The figure gives an indication of the historically realised operating margins by showing how profitability played out for a plant built at the beginning of 2008.

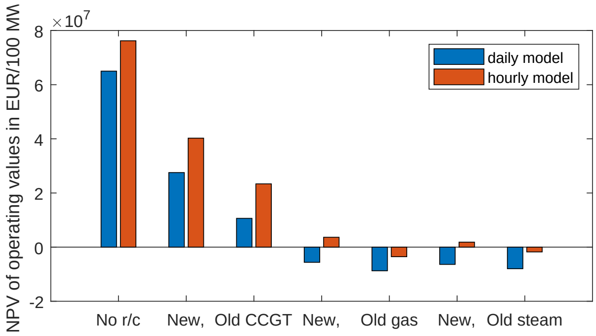
All overall measures of profitability for the different plants (figures 2.5.5a, 2.5.5b, 2.5.5c) are higher, sometimes considerably, in the hourly model than in the daily model. The average of the monthly



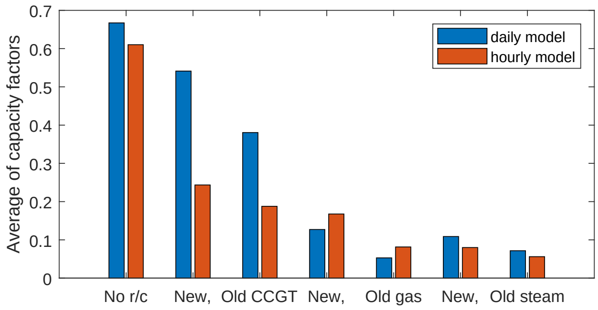
(a) Average operating values over 1 month



(b) Average construction values over 32 years



(c) Net present value of sum of operating values from 2008 to June 2017



(d) Average of capacity factors for each period of simulation

Figure 2.5.5: Comparison of overall results of the hourly and the daily model

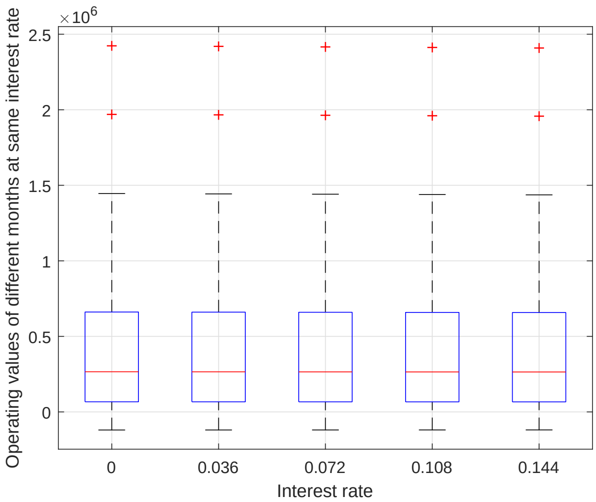
operating values for a new CCGT plant is with 422,832 EUR (2.5.5a) one third higher in the hourly than in the daily model. For old CCGT plants the hourly value is with 231,482 EUR around 2.5 times the daily value. Similarly, average construction values for a new CCGT plant in the daily model are with a negative -38,981,152 EUR less than double the (negative) average in the hourly model.

The most profitable plant is, unsurprisingly, the hypothetical plant without ramping and costs (*"No r/c"*). It is followed by the new and the old CCGT plant. It is noticeable that in figure 2.5.5c, only the hypothetical, the CCGT plants as well as the new gas and steam turbines achieved positive profits in the hourly model. As the net present value of operating profit is negative for old gas and steam turbines, if operators had precisely forecast prices, they would have been better off mothballing all old gas and steam turbines in 2008. The daily model would have even advised to mothball new gas and steam turbines - another indication that it is crucial to model hourly time steps.

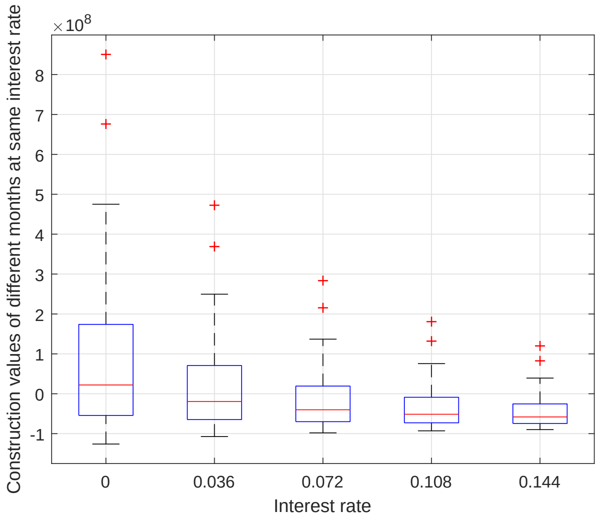
Regarding capacity factors (figure 2.5.5d), except for gas turbines, the averages are higher in the daily model. This is simply due to the bigger time steps, which force the operators to run the plant at least one full day at a time. It does not, as the previous analysis shows, indicate higher profitability in the daily model. In the case of gas turbines in the hourly model, immediate ramping enables the operator to make use of more positive-spread hours and thereby leads to higher capacity factors, as explained in section 2.5.1.

2.5.5 Sensitivity analysis of interest rates

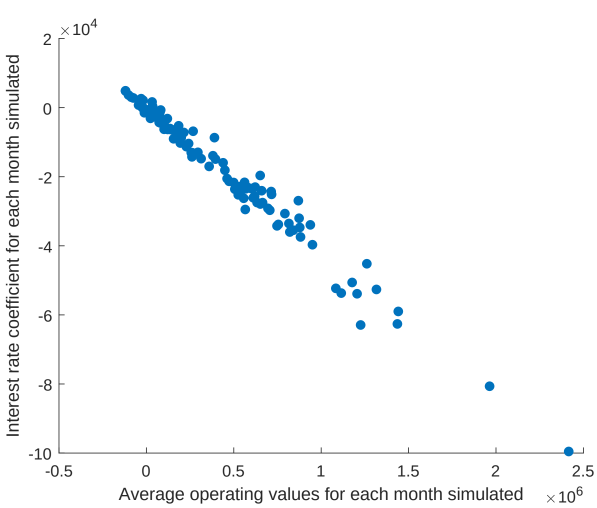
To keep the analysis simple, a discount rate of 7.2 % has been used throughout the paper as a rough estimate of the firm's cost of capital (KPMG 2012). In reality, the discount rate used has a large impact especially on the construction values calculated over the lifetime of the plants. The following sensitivity tests have been performed for the new CCGT plant parameters and the hourly model.



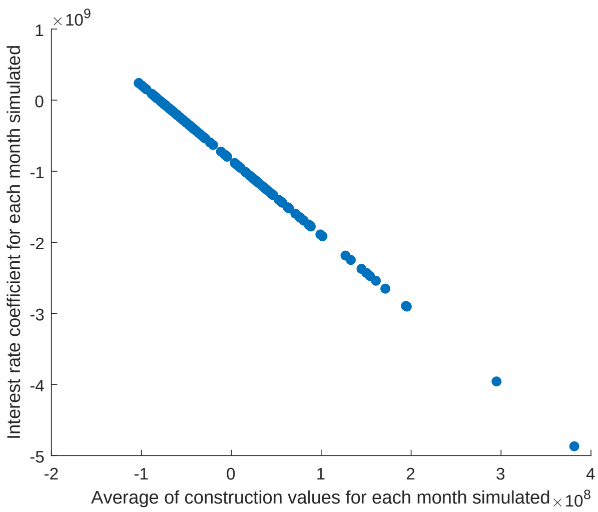
(a) Operating value



(b) Construction value



(c) Operating value



(d) Construction value

Figure 2.5.6: Relationship of profit measures and interest rates

Figure 2.5.6a and 2.5.6b show the box plots of the values simulated for different months at the same interest rate. While the dispersion of operating values is similar for different interest rates, the dispersion of construction values, calculated as the NPV of operating values over 32 years, dramatically shrinks for higher interest rates. The average difference between a monthly operating value discounted at 0% and one discounted at 14.4% is 0.65%, whereas for the construction values the average difference is 446%.[3]

Figures 2.5.6c and 2.5.6d show the simple ordinary least squares regression coefficient of the operating and construction values on the interest rate. The coefficient is generally negative: the higher the interest rate, the lower the operating and construction values. However, for some values, the coefficient becomes positive. Plotting the coefficient against the average values for each month reveals that the coefficient decreases and thereby takes on larger negative values with increasing averages for each month simulated. The interest rate coefficient only becomes positive for very small and mostly negative average operating and construction values, indicating that in these cases a higher interest rate led to "less negative" values. The values in the left hand scatter plot (figure 2.5.6c) are slightly less linear because operating values are received from a probabilistic model: the impact of the interest rate depends on the relative probabilities and size of positive and negative operating values. While positive values tend to result in a negative coefficient, negative values tend to result in a positive one, and the overall coefficient depends on the overall likelihood of different operating values realised with optimised ramping decisions.

The impact of the discount rate is decisive especially for the construction values as evidenced in the impact on the boxplots and in the very low interest rate coefficients in figure 2.5.6. This is also shown in figure 2.5.7: whereas for a 3.6% discount rate, a monthly operating value of EUR 400,000 is sufficient to make an investment in a new CCGT plant worthwhile, at a rate of 7.2% the operating value should be more in the range of EUR 600,000 and above, and at a 10.8% discount rate, the power plant operator already needs a monthly operating margin of around EUR 800,000. These results illustrate the sensitivity of electricity generation profits to interest rates due to the longevity of the assets. The interest rates reflect the cost of capital of the investor, which depends on macroeconomic factors and on the risk-return profile of each project, which in turn is affected by power prices. Financing costs represent thus an additional indirect channel through which power prices impact gas-fired generation's profits.

[3]The difference is defined as $\triangle V = \frac{V_{max} - V_{min}}{|V_{min}|}$.

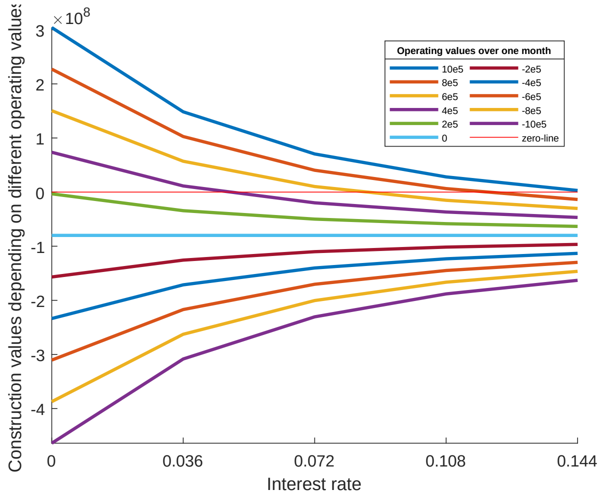


Figure 2.5.7: Relationship between monthly operating values and construction values at different interest rates

2.6 Conclusion

The goal of this paper was twofold. First, the relevant literature was analysed and a model was developed that improved upon existing ones in several ways: electricity and gas prices were modelled as a two-dimensional stochastic process, each component consisting of the sum of a deterministic seasonal part and a mean-reverting process. A power plant model for different types of gas-fired power plants incorporated ramping times and costs and it was run in daily and hourly time steps. Second, the results of two types of gas plant models were compared, one with daily and one with hourly time steps. The results show that modelling ramping times and costs pay off: operating and construction values of plants modelled without costs are at all times higher and average values are significantly higher than when including the ramping and other costs. Modelling ramping times is only relevant for capacity factors and not for the profit indicators. The reason might be that the additional hours during which a faster plant can be profitably operated contribute only little to the overall profit because they exhibit low spreads between electricity and gas prices.

When comparing daily and hourly models, the result is that, for gas-fired power plants, time step size matters. Average operating and construction values in the hourly model are more than double of what is derived with a daily model. The reason is that with hourly time steps, operators can benefit from jumps in prices as occurred in January 2017. Due to these results and because in reality gas-fired power plants are used as peakers with operation being optimised at least hourly, the hourly model is clearly preferable to the daily one.

As quarter hourly electricity prices are traded on the EPEX exchange, it is conceivable to model even smaller time steps of 30 or only 15 minutes. But while capacity factors are likely to increase if granularity was further improved, profits would probably stay in a similar range, as similar profits of the two hypothetical power plants - one fast and one slow, but otherwise comparable - indicate.

The hourly model replicates operators' and investors' decision making very well as the results trace current major developments like the recent decline and come-back of gas-fired power in Germany. From 2008 profits showed a decreasing tendency and from 2013 to 2016, all plants but CCGTs operated at a loss and ran at very low, sometimes zero, capacity. The recent rise in profitability can partly be seen in the model: capacity factors and operating profits displayed an increasing tendency from mid-2015. Construction values from 2013, however, were only positive in December 2016 and January 2017, due to a surge in hourly electricity prices. The reason for operators nevertheless building new plants in this period can be explained if we assume that they used future rather than historical prices to evaluate their investment options and that future prices indicated an increase in the electricity-gas-spread.

The sensitivity of construction values to changes in the discount rate illustrates the importance of financing costs due to the longevity of electricity generation assets. Financing costs represent an additional indirect channel through which power prices impact gas-fired generation's profits.

2.7 Further research and outlook

Future research could extend this model in several ways. First, while this paper uses historical spot prices and thereby models factual profitability of power plants during a certain time period in the past, a possible extension would be to use future prices. Using futures, the results would get closer to the decision making of operators, who have to take investment decisions that lock them in for around 30 years into the future. A whole separate body of literature is concerned with building the "hourly price forward curve" (HPFC) in order to receive hourly future prices that are consistent with all future products traded on the market at a certain point in time (e.g. Paraschiv et al 2015). By marrying this strand of literature with the model presented in this paper, one could get one step closer to the real decision making process of operators.

Second, it might be worthwhile to incorporate price jumps rather than mean reversion only into the price model (see for example Keles et al 2012). Especially for future electricity markets with even higher shares of variable renewable electricity this step might be worthwhile.

Third, the results show that differences between the types of power plants are large. In order to deduce results that hold for an entire sector and to test the behaviour of specific types of plants, a larger number of models could be calibrated to more accurately reflect different technologies and thereby explain the relative importance of different plant types.

A fourth extension to this model, and real options in general, could be in other areas of energy economics that are currently intensively researched, such as (battery) storage: one could model the option to sell stored electricity and consider the costs incurred while storing it.

The paper contributes to a better understanding of the choices operators and investors face in the electricity market. This is currently all the more important as electricity markets are shaped by market factors and new policies for the transition to renewable energies in Germany and across Europe. In this context, four major developments might favour investments in new gas-fired power plants in the coming years in Germany. Further research in this area is needed to determine exactly how these changes might impact the financial attractiveness of gas-fired and other power plants.

First, there have been several suggestions for measures to incentivise investment into flexible capacity. Researchers have analysed capacity markets, which, unlike energy-only markets, remunerate the capacity built and not the electricity generated. For the time being, legislators in Germany decided against it but recently created the possibility for transmission grid operators to auction off an additional capacity reserve, which is part of the ancillary services provided to stabilise the grid. New gas-fired power plants in the south of Germany are likely benefactors (Energate 2017). Ancillary services in general are of growing importance and an interesting area for research. Most of the services intended to stabilise the grid are requested by transmission system operators on an obligatory basis from power plant operators. Only the balancing power market is organised via capacity auctions. In both cases, ancillary services require different modelling techniques than the price-taker model employed in this paper (Bundesnetzagentur 2017).

Second, the so-called "back-loading initiative" by the European Commission has come into effect in 2018 and contributed to a supply reduction and thereby price increase on the EU emissions trading market favouring low-emitting electricity sources (Graichen et al 2018).

Third, the phase-out of nuclear power in Germany by 2022 is likely to have an increasing effect on power prices and thereby making all remaining energy sources more profitable.

And fourth, if European countries want to reach their climate goals under the Paris agreement, experts have argued that a coal phase out might be necessary (Heinrichs et al 2017). The German Federal "Special Commission on Growth, Structural Economic Change and Employment" is currently working on policy recommendations for the early closure of coal power plants - a step that might push gas-fired power plants further into the money.

Modelling power plant capacity factors and profitability more realistically thus has increasing relevance not just in academic research, but also for policy makers and investors.

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2.9 Appendix

2.9.1 Estimating the seasonalities

2.9.1.1 Long-term trend

First, for both daily and hourly model, a long-term trends is estimated by ordinary least squares regression and removed if the confidence interval is at least 90%.

$$Trend_{S_t} = \alpha + \beta \cdot t \tag{2.9.1}$$

This and the following steps are done accordingly for the gas price P_t.

2.9.1.2 Monthly means (daily model)

In the daily model, the monthly means are then calculated and subtracted, whereas we differentiate whether the day is a weekday or a weekend:

$$MonthlyMeans_{S_t} = \sum_{m=1}^{12} \{1(m'|m' = m(t)) \cdot \sum_{t=1}^{T} [\overline{S_t} \cdot 1(d'|d' = d(t))]\} \qquad \forall d = \{weekday, weekend\} \tag{2.9.2}$$

2.9.1.3 Daily means (hourly model)

In the hourly model, as only one month is modelled at a time, the daily averages are instead subtracted, whereas we again differentiate whether the day is a weekday or weekend:

$$DailyMeans_{S_t} = \sum_{t=1}^{T} \{1(d'|d' = d(t)) \cdot \sum_{h=1}^{24} [S_{X_h} \cdot 1(h|h = t \bmod 24)]\} \qquad \forall d = \{weekday, weekend\} \tag{2.9.3}$$

2.9.1.4 Weekly and other cycles (daily model)

Finally, cycles are estimated that follow the oscillation of sinus and cosinus curves with different lengths. They are estimated by an ordinary least squares regression and removed if the confidence interval is at least 90%. In the daily model, as T equals six months, a function with period lengths that range from six months (for $l = 1, m = 1$) to less than one week (for $n = 5, o = 5$) is fitted:

$$\begin{aligned} WeeklyAndOtherCyclesDaily_{S_t} = \gamma &+ \sum_{l=1}^{5} (\delta_l sin \frac{l \cdot \pi \cdot t}{T}) + \sum_{m=1}^{5} (\epsilon_m sin \frac{m \cdot \pi \cdot t}{T}) \\ &+ \sum_{n=1}^{5} (\zeta_n cos \frac{n \cdot 6 \cdot \pi \cdot t}{T}) + \sum_{o=1}^{5} (\eta_o cos \frac{o \cdot 6 \cdot \pi \cdot t}{T}) \end{aligned} \tag{2.9.4}$$

2.9.1.5 Weekly and other cycles (hourly model)

In the hourly model, as T equals one month, a function with period lengths that range from one month (for $m = 1$, $o = 1$) to less than one week (for $m = 5$, $n = 5$) is fitted:

$$WeeklyAndOtherCyclesHourly_{S_t} = \sum_{m=1}^{5}(\epsilon_m sin\frac{m \cdot \pi \cdot t}{T}) + \sum_{o=1}^{5}(\eta_o cos\frac{o \cdot \pi \cdot t}{T}) \qquad (2.9.5)$$

2.9.2 Ornstein-Uhlenbeck parameters and goodness of fit of daily price model

See table 2.2 and 2.3.

2.9.3 Goodness of fit of hourly price model

See table 2.4 and 2.5.

Table 2.4: Goodness of fit of hourly price model for electricity price S_t

Year	Part of year	Mean of historic X_t	Mean of simulated X_t	Mean of historic S_t	Mean of simulated S_t	SD of historic S_t	SD of simulated S_t	R^2 of simulated S_t
2008	1	0.00	0.74	56.00	56.74	20.42	18.22	78.98%
2008	2	0.00	0.28	59.47	59.75	16.57	15.67	85.68%
2008	3	0.00	1.43	53.30	54.73	19.29	16.57	72.34%
2008	4	0.00	0.89	67.46	68.35	25.33	23.85	84.46%
2008	5	0.00	1.10	56.24	57.34	23.15	21.17	79.16%
2008	6	0.00	-0.66	73.24	72.57	30.83	28.79	84.96%
2008	7	0.00	-0.84	69.94	69.11	25.81	23.55	83.21%
2008	8	0.00	0.15	61.76	61.91	22.80	20.78	83.85%
2008	9	0.00	-0.62	88.30	87.68	27.95	26.83	89.84%
2008	10	0.00	0.70	85.65	86.35	36.21	32.59	77.95%
2008	11	0.00	0.49	63.72	64.21	33.31	27.79	66.78%
2008	12	0.00	-1.14	54.55	53.41	27.80	24.15	74.60%
2009	1	0.00	1.42	57.12	58.54	21.83	20.19	73.76%
2009	2	0.00	0.47	47.79	48.26	16.08	14.33	76.39%
2009	3	0.00	0.20	37.15	37.35	13.06	10.42	62.54%
2009	4	0.00	0.43	33.05	33.48	12.08	10.90	77.91%
2009	5	0.00	0.52	30.93	31.45	15.94	12.67	61.15%
2009	6	0.00	0.07	33.21	33.29	12.07	10.72	80.69%
2009	7	0.00	-0.66	35.52	34.87	12.10	10.62	78.56%
2009	8	0.00	0.61	36.07	36.68	14.99	13.35	79.57%
2009	9	0.00	-0.39	39.58	39.19	15.76	14.89	88.18%
2009	10	0.00	0.06	44.57	44.63	29.66	20.31	45.83%
2009	11	0.00	-0.41	35.94	35.53	17.62	14.77	69.47%

Table 2.4: Goodness of fit of hourly price model for electricity price S_t

Year	Part of year	Mean of historic X_t	Mean of simulated X_t	Mean of historic S_t	Mean of simulated S_t	SD of historic S_t	SD of simulated S_t	R^2 of simulated S_t
2009	12	0.00	-0.48	35.69	35.22	25.02	19.56	58.35%
2010	1	0.00	0.26	42.21	42.46	12.88	11.07	69.84%
2010	2	0.00	0.17	41.73	41.90	12.81	12.18	88.64%
2010	3	0.00	-0.54	39.17	38.63	12.52	11.57	79.87%
2010	4	0.00	0.22	40.04	40.26	10.63	9.26	70.78%
2010	5	0.00	0.50	41.17	41.67	14.02	12.79	78.72%
2010	6	0.00	-0.01	43.34	43.34	13.83	13.15	85.18%
2010	7	0.00	-0.21	45.83	45.62	11.17	10.36	83.95%
2010	8	0.00	0.17	39.80	39.97	12.17	10.67	80.06%
2010	9	0.00	-0.17	45.86	45.69	11.66	10.90	86.60%
2010	10	0.00	0.02	50.31	50.33	11.93	10.80	82.22%
2010	11	0.00	0.55	48.53	49.08	14.05	13.10	83.85%
2010	12	0.00	-0.02	55.55	55.52	18.30	16.61	80.65%
2011	1	0.00	0.27	50.13	50.40	16.05	14.37	81.12%
2011	2	0.00	0.85	50.86	51.71	14.22	13.51	80.48%
2011	3	0.00	0.19	54.40	54.59	9.67	8.41	78.48%
2011	4	0.00	-0.25	51.58	51.33	11.73	10.23	70.48%
2011	5	0.00	-0.29	56.83	56.54	12.01	11.21	81.55%
2011	6	0.00	0.43	52.30	52.73	13.20	11.35	68.84%
2011	7	0.00	-0.02	46.40	46.38	12.45	11.52	80.76%
2011	8	0.00	0.64	48.57	49.21	11.47	10.66	82.36%
2011	9	0.00	0.44	52.64	53.08	13.19	12.17	85.28%
2011	10	0.00	0.45	51.68	52.13	13.27	12.22	84.10%
2011	11	0.00	0.25	55.36	55.61	15.01	14.20	88.04%
2011	12	0.00	0.19	42.90	43.09	13.82	12.67	80.06%
2012	1	0.00	0.54	39.89	40.43	15.99	12.84	66.58%
2012	2	0.00	-0.03	54.92	54.89	25.36	21.15	70.20%
2012	3	0.00	0.49	41.09	41.58	12.64	11.34	79.41%
2012	4	0.00	0.15	43.57	43.72	13.48	11.95	72.19%
2012	5	0.00	-0.53	38.85	38.32	11.96	9.64	64.91%
2012	6	0.00	0.39	38.81	39.19	13.40	13.29	85.27%
2012	7	0.00	-0.20	41.02	40.82	11.72	10.95	83.10%
2012	8	0.00	0.03	44.90	44.93	11.30	9.99	78.51%
2012	9	0.00	-0.14	44.67	44.53	13.13	12.20	80.52%
2012	10	0.00	-0.43	43.94	43.51	13.74	12.24	75.75%
2012	11	0.00	0.64	44.79	45.43	16.09	14.21	81.11%

Table 2.4: Goodness of fit of hourly price model for electricity price S_t

Year	Part of year	Mean of historic X_t	Mean of simulated X_t	Mean of historic S_t	Mean of simulated S_t	SD of historic S_t	SD of simulated S_t	R^2 of simulated S_t
2012	12	0.00	-0.59	35.51	34.92	38.72	30.23	62.87%
2013	1	0.00	0.69	43.31	44.00	16.21	14.85	87.33%
2013	2	0.00	-0.93	44.62	43.68	13.60	13.82	79.97%
2013	3	0.00	-0.13	39.06	38.93	17.18	15.69	75.59%
2013	4	0.00	0.30	37.92	38.22	16.63	14.79	75.65%
2013	5	0.00	1.22	32.06	33.29	13.30	10.95	71.23%
2013	6	0.00	0.91	27.82	28.73	14.64	12.01	67.09%
2013	7	0.00	-0.14	36.42	36.28	11.52	10.88	80.50%
2013	8	0.00	0.51	38.23	38.75	12.69	11.09	76.42%
2013	9	0.00	0.51	41.71	42.23	15.38	14.53	83.83%
2013	10	0.00	-0.04	37.72	37.67	16.22	14.38	75.20%
2013	11	0.00	0.90	39.22	40.11	17.15	15.03	79.10%
2013	12	0.00	-0.30	35.75	35.45	22.84	20.09	74.94%
2014	1	0.00	0.78	35.87	36.66	15.77	13.73	78.92%
2014	2	0.00	0.51	33.59	34.10	13.37	12.22	79.83%
2014	3	0.00	0.25	31.01	31.26	14.40	12.59	73.73%
2014	4	0.00	0.26	31.58	31.84	10.52	9.49	73.92%
2014	5	0.00	0.72	30.63	31.35	11.94	9.48	61.20%
2014	6	0.00	-0.24	31.52	31.28	9.27	8.88	76.02%
2014	7	0.00	0.08	31.88	31.96	6.31	5.70	82.05%
2014	8	0.00	0.12	27.93	28.05	11.52	10.26	73.94%
2014	9	0.00	-0.62	34.79	34.17	9.67	8.82	79.47%
2014	10	0.00	-0.01	35.25	35.24	12.28	11.00	76.94%
2014	11	0.00	0.52	36.37	36.89	13.64	12.56	83.88%
2014	12	0.00	-0.76	32.89	32.13	17.71	15.96	84.32%
2015	1	0.00	1.59	28.72	30.31	14.85	12.62	73.76%
2015	2	0.00	0.16	36.72	36.88	12.55	11.94	77.32%
2015	3	0.00	0.39	31.31	31.70	12.98	11.64	79.95%
2015	4	0.00	-0.30	29.72	29.42	13.22	10.98	62.50%
2015	5	0.00	0.38	25.36	25.73	9.95	8.32	66.17%
2015	6	0.00	-0.37	30.06	29.69	8.59	7.74	70.58%
2015	7	0.00	0.16	35.00	35.16	12.50	10.62	72.66%
2015	8	0.00	0.08	31.61	31.69	9.10	8.23	82.67%
2015	9	0.00	0.04	31.88	31.92	11.47	9.99	74.46%
2015	10	0.00	0.09	39.38	39.47	11.34	10.18	77.78%
2015	11	0.00	0.69	32.39	33.08	13.92	12.31	72.86%

Table 2.4: Goodness of fit of hourly price model for electricity price S_t

Year	Part of year	Mean of historic X_t	Mean of simulated X_t	Mean of historic S_t	Mean of simulated S_t	SD of historic S_t	SD of simulated S_t	R^2 of simulated S_t
2015	12	0.00	-0.61	27.78	27.18	13.19	11.44	78.30%
2016	1	0.00	0.70	29.04	29.74	13.30	11.90	78.36%
2016	2	0.00	0.51	21.99	22.50	9.47	8.55	78.34%
2016	3	0.00	-0.19	24.28	24.09	8.16	6.60	63.30%
2016	4	0.00	0.00	24.21	24.21	5.85	5.14	77.10%
2016	5	0.00	0.16	22.54	22.70	13.55	11.07	58.23%
2016	6	0.00	0.02	27.69	27.71	6.90	6.30	77.80%
2016	7	0.00	0.47	27.19	27.65	7.24	5.87	66.49%
2016	8	0.00	0.02	27.18	27.21	7.25	6.67	78.30%
2016	9	0.00	0.19	30.49	30.68	7.90	6.69	75.36%
2016	10	0.00	0.11	37.14	37.25	9.66	8.32	76.39%
2016	11	0.00	0.46	38.22	38.68	13.87	11.58	66.57%
2016	12	0.00	-0.35	37.48	37.12	21.06	19.34	79.98%
2017	1	0.00	0.00	52.37	52.37	25.82	23.31	76.95%
2017	2	0.00	0.49	39.70	40.19	16.05	14.70	79.05%
2017	3	0.00	0.41	31.70	32.11	9.69	8.17	67.93%
2017	4	0.00	0.18	28.87	29.05	13.49	10.55	57.93%
2017	5	0.00	-1.92	30.46	28.54	13.91	12.18	50.19%
2017	6	0.00	0.31	30.00	30.31	9.61	8.22	69.79%

Table 2.2: Ornstein-Uhlenbeck parameters and goodness of fit of daily price model for electricity price S_t

Year	Part of year	μ_X	σ_X	κ_X	Mean of historic X_t	Mean of simulated X_t	Mean of historic S_t	Mean of simulated S_t	SD of historic S_t	SD of simulated S_t	R^2 of simulated S_t	ρ
2008	1	0.55	193.30	182.00	0.00	0.14	60.87	61.01	14.19	12.35	69.90%	0.00%
2008	2	-0.25	247.58	184.00	0.00	-0.21	70.59	70.38	20.22	17.35	75.49%	3.04%
2009	1	0.39	144.65	181.00	0.00	0.10	39.83	39.93	12.59	10.70	77.42%	2.92%
2009	2	-0.25	192.90	184.00	0.00	-0.06	37.89	37.83	11.03	7.40	47.67%	11.94%
2010	1	0.37	119.09	181.00	0.00	0.05	41.27	41.32	7.58	6.48	62.99%	11.69%
2010	2	-0.19	114.65	184.00	0.00	-0.15	47.65	47.50	8.79	7.08	66.86%	11.66%
2011	1	0.23	131.84	181.00	0.00	0.02	52.73	52.75	8.17	6.33	49.46%	15.30%
2011	2	0.03	112.46	184.00	0.00	0.01	49.54	49.55	8.18	6.43	64.14%	18.47%
2012	1	0.29	174.61	182.00	0.00	0.12	42.75	42.87	11.70	9.44	62.24%	34.16%
2012	2	-0.26	206.15	184.00	0.00	-0.07	42.45	42.38	13.87	9.48	51.14%	13.61%
2013	1	0.40	161.27	181.00	0.00	0.11	37.40	37.52	11.98	10.26	68.31%	20.99%
2013	2	-0.06	168.71	184.00	0.00	0.01	38.15	38.16	11.00	8.20	57.18%	21.68%
2014	1	0.26	132.00	181.00	0.00	0.04	32.36	32.41	8.64	6.80	61.98%	3.48%
2014	2	-0.04	123.57	184.00	0.00	0.01	33.16	33.16	8.83	6.59	56.44%	15.19%
2015	1	0.21	136.74	181.00	0.00	0.08	30.22	30.29	8.96	6.84	56.76%	1.00%
2015	2	-0.01	130.51	184.00	0.00	-0.06	33.01	32.95	8.73	6.64	56.55%	16.29%
2016	1	0.09	113.21	182.00	0.00	0.06	24.98	25.04	7.25	5.50	54.83%	14.31%
2016	2	0.01	153.15	184.00	0.00	0.06	32.93	32.99	10.11	6.59	45.67%	13.84%
2017	1	0.14	196.25	181.00	0.00	0.08	35.51	35.60	14.23	11.09	59.80%	27.98%

Table 2.3: Ornstein-Uhlenbeck parameters and goodness of fit of daily price model for gas price P_t

Year	Part of year	μ_Y	σ_Y	κ_Y	Mean of historic Y_t	Mean of simulated Y_t	Mean of historic P_t	Mean of simulated P_t	SD of historic P_t	SD of simulated P_t	R^2 of simulated P_t
2008	1	-0.01	9.79	173.65	0.00	-0.02	24.84	24.82	1.60	1.52	89.55%
2008	2	0.01	24.70	184.00	0.00	0.00	26.06	26.07	3.20	3.05	86.33%
2009	1	0.04	24.75	119.60	0.00	0.03	15.40	15.43	5.71	5.62	92.38%
2009	2	0.00	12.47	151.00	0.00	0.01	10.05	10.06	1.63	1.54	80.20%
2010	1	0.02	13.35	181.00	0.00	-0.02	14.94	14.92	2.45	2.38	92.07%
2010	2	0.00	15.21	184.00	0.00	0.02	19.85	19.87	2.36	2.31	90.06%
2011	1	-0.04	10.37	152.46	0.00	-0.02	22.78	22.76	0.96	0.84	63.33%
2011	2	-0.03	15.84	184.00	0.00	0.00	22.52	22.51	1.81	1.66	81.21%
2012	1	0.03	23.68	182.00	0.00	0.06	24.13	24.19	2.03	1.70	68.09%
2012	2	-0.02	6.39	184.00	0.00	0.00	25.83	25.83	1.40	1.40	94.60%
2013	1	0.01	18.64	181.00	0.00	0.06	27.53	27.59	2.08	1.95	82.11%
2013	2	-0.01	5.99	184.00	0.00	0.00	26.59	26.59	0.82	0.79	89.51%
2014	1	0.01	8.05	181.00	0.00	0.00	21.78	21.78	3.18	3.13	98.59%
2014	2	-0.03	10.89	184.00	0.00	0.00	20.17	20.16	2.68	2.59	96.12%
2015	1	-0.01	7.93	181.00	0.00	-0.01	21.31	21.30	1.05	1.00	84.78%
2015	2	0.00	5.77	184.00	0.00	0.02	18.65	18.67	1.78	1.77	98.10%
2016	1	0.01	8.38	182.00	0.00	0.01	13.19	13.20	1.07	1.00	83.61%
2016	2	0.02	9.69	124.41	0.00	0.01	15.07	15.08	2.47	2.38	93.66%
2017	1	0.01	8.59	140.52	0.00	-0.01	17.40	17.39	2.18	2.14	94.51%

Table 2.5: Goodness of fit of hourly price model for gas price P_t

Year	Part of year	Mean of historic Y_t	Mean of simulated Y_t	Mean of historic P_t	Mean of simulated P_t	SD of historic P_t	SD of simulated P_t	R^2 of simulated P_t
2008	1	0.00	-0.09	24.05	23.96	0.99	0.99	91.80%
2008	2	0.00	0.06	22.85	22.91	0.55	0.56	84.01%
2008	3	0.00	0.01	23.61	23.62	0.30	0.27	84.39%
2008	4	0.00	-0.08	25.68	25.60	0.55	0.54	70.68%
2008	5	0.00	-0.06	25.58	25.52	0.53	0.44	81.80%
2008	6	0.00	0.03	27.15	27.18	0.76	0.72	93.92%
2008	7	0.00	0.01	26.60	26.61	1.23	1.12	89.46%
2008	8	0.00	0.05	24.16	24.21	2.28	2.26	95.56%
2008	9	0.00	-0.06	30.59	30.54	0.99	1.03	91.15%
2008	10	0.00	0.13	26.75	26.89	2.83	2.93	92.56%
2008	11	0.00	0.04	25.62	25.66	2.69	2.71	97.28%
2008	12	0.00	-0.01	22.83	22.81	1.24	1.17	89.74%
2009	1	0.00	-0.15	25.06	24.91	3.04	3.03	91.54%
2009	2	0.00	-0.03	20.35	20.32	3.64	3.54	98.54%
2009	3	0.00	0.08	13.29	13.37	0.83	0.82	91.82%
2009	4	0.00	-0.02	11.87	11.85	0.51	0.44	81.35%
2009	5	0.00	0.09	11.41	11.49	0.28	0.23	55.79%
2009	6	0.00	0.06	10.94	11.00	0.36	0.36	87.06%
2009	7	0.00	0.01	9.53	9.54	0.77	0.78	95.93%
2009	8	0.00	0.03	8.66	8.70	0.82	0.81	95.35%
2009	9	0.00	-0.02	9.18	9.17	0.67	0.64	88.90%
2009	10	0.00	0.16	11.16	11.32	2.35	2.22	94.98%
2009	11	0.00	-0.01	10.42	10.41	0.94	0.91	95.28%
2009	12	0.00	0.04	11.27	11.32	1.20	1.16	96.61%
2010	1	0.00	-0.08	14.24	14.15	1.13	1.13	84.13%
2010	2	0.00	0.02	14.15	14.17	1.08	1.00	91.93%
2010	3	0.00	-0.03	12.14	12.11	0.70	0.69	93.13%
2010	4	0.00	-0.05	13.43	13.38	0.59	0.60	87.05%
2010	5	0.00	-0.01	16.75	16.74	0.77	0.80	91.69%
2010	6	0.00	0.02	18.79	18.81	1.29	1.27	96.31%
2010	7	0.00	-0.09	19.67	19.58	1.50	1.50	95.78%
2010	8	0.00	0.00	18.15	18.15	0.27	0.24	72.22%
2010	9	0.00	0.00	18.84	18.84	0.50	0.39	51.92%
2010	10	0.00	0.08	18.60	18.68	1.07	1.06	86.49%
2010	11	0.00	0.03	19.31	19.34	1.21	1.20	97.97%
2010	12	0.00	-0.04	24.34	24.30	0.86	0.83	78.06%

Table 2.5: Goodness of fit of hourly price model for gas price P_t

Year	Part of year	Mean of historic Y_t	Mean of simulated Y_t	Mean of historic P_t	Mean of simulated P_t	SD of historic P_t	SD of simulated P_t	R^2 of simulated P_t
2011	1	0.00	0.00	22.94	22.94	1.07	1.10	95.34%
2011	2	0.00	-0.04	21.84	21.80	0.34	0.34	91.74%
2011	3	0.00	-0.04	23.73	23.69	0.85	0.83	92.19%
2011	4	0.00	-0.13	22.80	22.67	1.04	0.99	87.91%
2011	5	0.00	-0.01	22.76	22.75	0.49	0.49	90.32%
2011	6	0.00	-0.06	22.58	22.52	0.49	0.45	92.58%
2011	7	0.00	-0.01	21.68	21.68	0.31	0.27	67.99%
2011	8	0.00	-0.02	21.48	21.46	0.89	0.89	95.54%
2011	9	0.00	0.01	23.56	23.57	1.41	1.27	88.03%
2011	10	0.00	0.10	21.85	21.95	3.09	2.92	97.67%
2011	11	0.00	0.01	23.89	23.90	0.69	0.65	89.15%
2011	12	0.00	0.01	22.75	22.77	0.87	0.80	89.62%
2012	1	0.00	-0.03	21.74	21.71	0.67	0.69	88.99%
2012	2	0.00	-0.23	26.14	25.91	3.45	3.35	85.79%
2012	3	0.00	0.00	24.10	24.10	0.77	0.75	92.80%
2012	4	0.00	0.00	24.84	24.84	0.28	0.26	70.80%
2012	5	0.00	-0.04	24.31	24.27	0.83	0.79	91.79%
2012	6	0.00	0.02	23.72	23.75	0.48	0.45	78.50%
2012	7	0.00	-0.03	24.34	24.31	0.51	0.51	93.84%
2012	8	0.00	-0.01	24.03	24.02	0.59	0.58	86.48%
2012	9	0.00	-0.02	25.61	25.59	0.37	0.35	91.70%
2012	10	0.00	-0.02	26.57	26.56	0.68	0.69	97.56%
2012	11	0.00	0.01	27.19	27.21	0.22	0.21	79.06%
2012	12	0.00	-0.02	27.26	27.24	0.62	0.62	97.68%
2013	1	0.00	0.00	26.85	26.85	0.46	0.46	92.92%
2013	2	0.00	-0.01	26.34	26.33	0.30	0.31	88.76%
2013	3	0.00	0.14	29.96	30.09	3.22	3.11	94.08%
2013	4	0.00	-0.08	28.47	28.39	2.01	1.90	95.32%
2013	5	0.00	0.03	26.97	27.00	0.24	0.23	86.45%
2013	6	0.00	0.02	26.47	26.49	0.21	0.22	90.72%
2013	7	0.00	-0.02	26.27	26.26	0.16	0.15	78.86%
2013	8	0.00	0.00	25.75	25.76	0.23	0.21	86.56%
2013	9	0.00	0.00	26.58	26.58	0.38	0.37	97.44%
2013	10	0.00	-0.02	26.26	26.25	0.46	0.44	89.87%
2013	11	0.00	0.04	26.97	27.01	0.93	0.87	96.28%
2013	12	0.00	-0.03	27.69	27.67	0.59	0.59	95.01%

Table 2.5: Goodness of fit of hourly price model for gas price P_t

Year	Part of year	Mean of historic Y_t	Mean of simulated Y_t	Mean of historic P_t	Mean of simulated P_t	SD of historic P_t	SD of simulated P_t	R^2 of simulated P_t
2014	1	0.00	0.03	26.51	26.54	0.30	0.28	81.81%
2014	2	0.00	0.03	24.29	24.32	0.66	0.69	97.35%
2014	3	0.00	0.05	22.91	22.95	0.90	0.88	92.36%
2014	4	0.00	0.03	20.70	20.74	0.67	0.65	87.92%
2014	5	0.00	0.07	19.29	19.36	0.34	0.31	67.34%
2014	6	0.00	0.05	17.24	17.29	0.55	0.57	91.08%
2014	7	0.00	0.01	16.40	16.41	0.88	0.89	95.15%
2014	8	0.00	0.01	17.26	17.27	0.82	0.82	95.55%
2014	9	0.00	-0.05	20.48	20.44	0.98	0.96	90.39%
2014	10	0.00	0.01	21.36	21.36	0.70	0.69	88.02%
2014	11	0.00	0.07	22.67	22.74	1.25	1.06	91.61%
2014	12	0.00	-0.02	22.84	22.82	0.67	0.66	95.85%
2015	1	0.00	0.01	20.11	20.12	0.50	0.51	94.72%
2015	2	0.00	-0.03	22.51	22.49	1.03	1.02	95.44%
2015	3	0.00	-0.01	21.96	21.96	0.56	0.54	95.32%
2015	4	0.00	-0.05	22.05	22.00	0.49	0.47	90.01%
2015	5	0.00	0.03	20.66	20.69	0.22	0.21	62.52%
2015	6	0.00	0.00	20.69	20.69	0.16	0.14	78.99%
2015	7	0.00	-0.02	20.95	20.94	0.18	0.18	81.96%
2015	8	0.00	0.01	19.85	19.86	0.58	0.58	94.47%
2015	9	0.00	0.00	19.35	19.35	0.31	0.30	89.96%
2015	10	0.00	0.03	18.48	18.51	0.26	0.22	77.01%
2015	11	0.00	0.01	17.37	17.39	0.55	0.55	95.85%
2015	12	0.00	-0.04	16.01	15.96	1.31	1.28	96.74%
2016	1	0.00	0.01	14.37	14.38	0.64	0.60	80.55%
2016	2	0.00	0.03	12.74	12.77	0.35	0.35	82.63%
2016	3	0.00	-0.01	12.46	12.45	0.26	0.24	89.12%
2016	4	0.00	0.03	12.10	12.13	0.92	0.93	94.49%
2016	5	0.00	0.00	13.01	13.01	0.44	0.43	93.41%
2016	6	0.00	0.00	14.45	14.45	0.39	0.37	88.73%
2016	7	0.00	0.06	14.39	14.45	0.31	0.28	78.67%
2016	8	0.00	0.01	12.18	12.18	0.89	0.87	96.56%
2016	9	0.00	0.04	12.34	12.39	0.77	0.75	93.14%
2016	10	0.00	0.08	15.73	15.81	1.41	1.32	97.86%
2016	11	0.00	-0.10	17.93	17.83	0.41	0.34	52.68%
2016	12	0.00	0.01	17.74	17.76	0.66	0.65	95.08%

Table 2.5: Goodness of fit of hourly price model for gas price P_t

Year	Part of year	Mean of historic Y_t	Mean of simulated Y_t	Mean of historic P_t	Mean of simulated P_t	SD of historic P_t	SD of simulated P_t	R^2 of simulated P_t
2017	1	0.00	0.04	20.28	20.32	0.85	0.82	93.04%
2017	2	0.00	-0.13	20.24	20.10	1.67	1.57	95.54%
2017	3	0.00	0.01	16.39	16.40	0.73	0.73	96.82%
2017	4	0.00	0.03	16.39	16.42	0.36	0.33	90.67%
2017	5	0.00	-0.01	15.98	15.97	0.41	0.38	89.43%
2017	6	0.00	0.04	15.42	15.46	0.23	0.23	69.97%

2.9.4 Power plant models

2.9.4.1 Hypothetical power plants

The hypothetical plant with immediate ramping and no costs is modelled as follows.
Type 1 - daily model:

$$R_t(a_t, S_t, P_t, w) = \begin{cases} 0 & \text{if } a_t = a_{\text{I}} \\ Q_{\min} \cdot 24 \cdot (S_t - Hr_{\max} \cdot P_t) & \text{if } a_t = a_{\text{II}} \quad \forall S_t, P_t, w_t = \{1,2\} \\ Q_{\max} \cdot 24 \cdot (S_t - Hr_{\min} \cdot P_t) & \text{if } a_t = a_{\text{III}} \end{cases} \tag{2.9.6}$$

Type 1 - hourly model:

$$R_t(a_t, S_t, P_t, w) = \begin{cases} 0 & \text{if } a_t = a_{\text{I}} \\ Q_{\min}(S_t - Hr_{\max} \cdot P_t) & \text{if } a_t = a_{\text{II}} \quad \forall S_t, P_t, w_t = \{1,2\} \\ Q_{\max}(S_t - Hr_{\min} \cdot P_t) & \text{if } a_t = a_{\text{III}} \end{cases} \tag{2.9.7}$$

2.9.4.2 Daily model

The operating profits of the power plants in the daily model are calculated as follows.
Type 3 to 8 - daily model:

$$R_t(a_t, S_t, P_t, 1) = \begin{cases} -c_{\text{fix}} \cdot \frac{Q_{\max}}{365} & \text{if } a_t = a_{\text{I}} \\ -c_{\text{fix}} \cdot \frac{Q_{\max}}{365} + Q_{\min} \cdot 24 \cdot [-c_{\text{start}} - c_{\text{ramp}} - c_{\text{var}} - price_{CO_2} \cdot CO2 + (S_t - Hr_{\max} \cdot P_t)] & \text{if } a_t = a_{\text{II}} \quad \forall S_t, P_t, w_t = 1 \\ -c_{\text{fix}} \cdot \frac{Q_{\max}}{365} + Q_{\max} \cdot 24 \cdot [-c_{\text{start}} - c_{\text{ramp}} - c_{\text{var}} - price_{CO_2} \cdot CO2 + (S_t - Hr_{\min} \cdot P_t)] & \text{if } a_t = a_{\text{III}} \end{cases} \tag{2.9.8}$$

$$R_t(a_t, S_t, P_t, 2) = \begin{cases} -c_{\text{fix}} \cdot \frac{Q_{\max}}{365} & \text{if } a_t = a_{\text{I}} \\ -c_{\text{fix}} \cdot \frac{Q_{\max}}{365} + Q_{\min} \cdot 24 \cdot [-c_{\text{var}} - price_{CO_2} \cdot CO2 + (S_t - Hr_{\max} \cdot P_t)] & \text{if } a_t = a_{\text{II}} \quad \forall S_t, P_t, w_t = 2 \\ -c_{\text{fix}} \cdot \frac{Q_{\max}}{365} + Q_{\max} \cdot 24 \cdot [-c_{\text{var}} - price_{CO_2} \cdot CO2 + (S_t - Hr_{\min} \cdot P_t)] & \text{if } a_t = a_{\text{III}} \end{cases} \tag{2.9.9}$$

2.9.4.3 Hourly model

Type 5 and 6:

$$R_t(a_t,S_t,P_t,1)=\begin{cases}-c_{\text{fix}}\cdot\frac{Q_{\max}}{8760} & \text{if } a_t=a_{\text{I}}\\ -c_{\text{fix}}\cdot\frac{Q_{\max}}{8760}+Q_{\min}[-c_{\text{start}}-c_{\text{ramp}}-c_{\text{var}}-price_{CO_2}\cdot CO2+(S_t-Hr_{\max}\cdot P_t)] & \text{if } a_t=a_{\text{II}}\\ -c_{\text{fix}}\cdot\frac{Q_{\max}}{8760}+Q_{\max}[-c_{\text{start}}-c_{\text{ramp}}-c_{\text{var}}-price_{CO_2}\cdot CO2+(S_t-Hr_{\min}\cdot P_t)] & \text{if } a_t=a_{\text{III}}\end{cases}\quad \forall S_t,P_t,w_t=1 \tag{2.9.10}$$

$$R_t(a_t,S_t,P_t,2)=\begin{cases}-c_{\text{fix}}\cdot\frac{Q_{\max}}{8760} & \text{if } a_t=a_{\text{I}}\\ -c_{\text{fix}}\cdot\frac{Q_{\max}}{8760}+Q_{\min}[-c_{\text{var}}-price_{CO_2}\cdot CO2+(S_t-Hr_{\max}\cdot P_t)] & \text{if } a_t=a_{\text{II}}\\ -c_{\text{fix}}\cdot\frac{Q_{\max}}{8760}+Q_{\max}[-c_{\text{var}}-price_{CO_2}\cdot CO2+(S_t-Hr_{\min}\cdot P_t)] & \text{if } a_t=a_{\text{III}}\end{cases}\quad \forall S_t,P_t,w_t=2 \tag{2.9.11}$$

Type 2, 3, 4, 7 and 8:

$$R_t(a_t,S_t,P_t,1)=\begin{cases}-c_{\text{fix}}\cdot\frac{Q_{\max}}{8760} & \text{if } a_t=a_{\text{I}}\\ -c_{\text{fix}}\cdot\frac{Q_{\max}}{8760} & \text{if } a_t=a_{\text{II}}\\ -c_{\text{fix}}\cdot\frac{Q_{\max}}{8760}+Q_{\min}[-c_{\text{ramp}}-c_{\text{start}}-c_{\text{var}}-price_{CO_2}\cdot CO2+(S_t-Hr_{\max}\cdot P_t)] & \text{if } a_t=a_{\text{III}}\end{cases}\quad \forall S_t,P_t,w_t=1 \tag{2.9.12}$$

$$R_t(a_t,S_t,P_t,2)=\begin{cases}-c_{\text{fix}}\cdot\frac{Q_{\max}}{8760} & \text{if } a_t=a_{\text{I}}\\ -c_{\text{fix}}\cdot\frac{Q_{\max}}{8760}+Q_{\min}[-c_{\text{var}}-price_{CO_2}\cdot CO2+(S_t-Hr_{\max}\cdot P_t)] & \text{if } a_t=a_{\text{II}}\\ -c_{\text{fix}}\cdot\frac{Q_{\max}}{8760}-c_{\text{ramp}}(Q_{\max}-Q_{\min})+Q_{\max}[-c_{\text{var}}-price_{CO_2}\cdot CO2+(S_t-Hr_{\min}\cdot P_t)] & \text{if } a_t=a_{\text{III}}\end{cases}\quad \forall S_t,P_t,w_t=2 \tag{2.9.13}$$

$$R_t(a_t,S_t,P_t,3)=\begin{cases}-c_{\text{fix}}\cdot\frac{Q_{\max}}{8760} & \text{if } a_t=a_{\text{I}}\\ -c_{\text{fix}}\cdot\frac{Q_{\max}}{8760}+Q_{\max}[-c_{\text{var}}-price_{CO_2}\cdot CO2+(S_t-Hr_{\min}\cdot P_t)] & \text{if } a_t=a_{\text{II}}\\ -c_{\text{fix}}\cdot\frac{Q_{\max}}{8760}+Q_{\max}[-c_{\text{var}}-price_{CO_2}\cdot CO2+(S_t-Hr_{\min}\cdot P_t)] & \text{if } a_t=a_{\text{III}}\end{cases}\quad \forall S_t,P_t,w_t=3 \tag{2.9.14}$$

2.9.5 Cost inputs for power plant model

See table 2.6.

Parameter name	**Value (new CCCGT; old CCGT; new gas turbine; old gas turbine; new steam; old steam) and unit**	**Details**	**Source**
c_{start}	21.05; 26.32; 16.54; 24.06; 18.80; 27.07 €/△ MW	Fuel-related start-up costs for hot start. 25th percentile (for new plants) and median value (for old plants). Hot start means the plant has been offline for 8 hours or less, warm start for more than 8 hours and cold start for more than 50 hours. Cold start occurs rarely, mainly for maintenance, and the model cannot distinguish between hot, warm and cold start.	Kumar et al (2012), p. 12.
c_{ramp}	0.25; 0.25; 0.66; 0.66; 1.17; 1.17 €/△ MW	Ramping cost.	Kumar et al (2012), p. 16.
c_{fix}	17,000; 17,000; 15,000; 15,000; 15,000; 15,000 €/MW/year	Fixed O&M cost.	Schröder et al (2013), p. 88.
c_{var}	2.1; 2.1; 2; 2; 2; 2 €/MWh	Variable O&M cost.	Schröder et al (2013), p. 88.
co_2	0.33; 0.36; 0.55; 0.55; 0.55; 0.55 t/MWh	CO_2 equivalent estimates in t/MWh.	Schröder et al (2013), p. 42.
$price_{co2}$	Between 4.48 and 22 €/t from 2008 to 2016	CO_2 prices as average of daily prices each year in €/t.	Bloomberg (2017).
Q_{max}	100; 100; 100; 100; 100; 100 MW	Maximum capacity of power plant calculated as average of net generation capacity of operating German gas-fired power plants.	Open Power System Data (2017).
L_{min}	40.33; 40.33; 33.13; 33.13; 40; 40%	Minimum load as percentage of maximum capacity, calculated as average value. Below the minimum load a stable operation is not possible due to insufficient temperature or excessive emissions.	Schröder et al (2013), p. 66.
Q_{min}	$L_{min} \cdot Q_{max}$	Minimum capacity of power plant in MW.	
Hr_{min}	1.67; 1.93; 2.43; 2.89; 2.50; 2.71	Minimum heat rate. For one unit electricity you need, if plant is running at maximum capacity, Hr_{min} units gas. Calculated via the average of efficiencies of German power plants built until (old) and after 2010 (new).	Open Power System Data (2017).
Hr_{max}	$1.1 \cdot Hr_{min}$	Maximum heat rate. For one unit electricity you need, if plant is running at minimum capacity, Hr_{max} units gas.	IEA (2015).
$discount$	7.20%	Weighted average cost of capital (WACC) for energy sector in Germany, Austria and Switzerland.	KPMG (2014).
I	800,000; 800,000; 400,000; 400,000; 400,000; 400,000 €/MW	Capital cost defined as greenfield and overnight investment cost, comprising the construction of a power plant excluding all interest effects.	Schröder et al (2013), p. 88.
$lifetime$	32 years	Lifetime of power plant. Calculated as average value.	Schröder et al (2013), p. 72.

Table 2.6: Cost inputs for power plant model

Chapter 3

Utility divestitures in Germany

A case study of corporate financial strategies and energy transition risk

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Abstract

Germany is in the midst of a radical transformation of its power sector, which in 2016 led two of its main electric utilities, EON and RWE, to undertake dramatic restructurings. EON spun off its fossil fuel and trading segments, while RWE carved out its renewable energy, retail and grid business.

The paper examines the drivers of these divestitures. Building on corporate finance literature, the paper uses a mix of comparative descriptive statistics, interviews and event studies to test four groups of hypotheses. The evidence rejects drivers related to operations and management, biased investment and investor preferences and instead points to financing-related drivers. Among the financing-related drivers, debt overhang and risk contamination seemed to have played the main role. Utilities restructured to save their healthy assets (renewables and grid infrastructure) from losses at their conventional power generation business (fossil fuel and nuclear plants).

The paper uses existing research on divestitures in an empirical case that has implications for the evolution of European power markets. The results suggest that exiting conventional technologies as part of the transition to a more renewable energy mix can cause substantial costs. If these are not clarified and allocated ex ante, policy makers find themselves forced to either burden tax payers or endanger utilities that are of systemic relevance to the energy sector.

Key words— Electric utilities; event study; risk; energy transition; nuclear power; renewable energy.

3.1 Introduction

Germany has set about a radical transformation of its electricity sector. After having supported fossil fuel- and nuclear-based power production since the 1950s, the government embarked on an increasingly green agenda in the 1990s. From 2000, renewable power plants were guaranteed grid priority and 20-year feed-in tariffs. In 2017, more than a third of electricity produced was from renewables. The exit from nuclear power was negotiated and amended several times between 2000 and 2011, resulting in a step-wise exit plan supposed to end nuclear electricity production by 2022. Power generation from nuclear plants decreased from 28% in 1990 to 12% in 2017. Current governmental efforts include a strategy to phase out coal-based electricity generation by 2038.

In recent years, the two biggest German electric utilities, EON and RWE - responsible for 37% of German power generation capacity in 2009 - had the most difficult times of their history. From 2010 their net income declined and by 2015 EON and RWE had booked the biggest net losses in their history: EUR -2.4 billion in 2013 (RWE) and -6.4 billion in 2015 (EON). From 2011 to 2015 they each wrote off more than 13% of their book asset value and lost between 70% (EON) and 80% (RWE) of their market capitalisation.

EON and RWE, until then integrated firms spanning the whole energy value chain, responded with two of the most dramatic restructuring moves in recent German corporate history and in the history of European utilities. In late 2014, EON announced that it would carve out a new subsidiary consisting of its fossil fuel, nuclear, hydro and trading segments. The original strategy was altered by the German government, which insisted that the parent firm remain liable for all future liabilities connected to nuclear energy, even if the nuclear plants are spun off. EON decided to carve out only fossil fuel- and hydro-based generation and the trading segment, the equivalent of 56% of EON's 2015 book asset value, into the new firm Uniper. It spun off 53.35% of Uniper to its existing shareholders in September 2016.

In December 2015, RWE announced that it would carve out renewable energies, retail and grid infrastructure, but keep a majority stake in the new firm Innogy. In October 2016, the IPO of Innogy, worth 73% of RWE's 2015 book asset value, the biggest flotation in Germany since 2000 and the second largest worldwide that year, raised EUR 4.6 billion. By the end of 2016, Innogy had a market capitalisation of EUR 18.3 billion - making it the biggest German energy utility (RWE 2016; Innogy 2016). RWE, on the other hand, its own operations solely based on nuclear, hydro, fossils and trading, depended on Innogy for 75% of their EBITDA (Innogy 2017; RWE 2017).

Why did EON and RWE divest and why did they differ in their approach? While the firms themselves argued that the restructurings would bring about a large array of benefits, encompassing almost all possible advantages ever discussed in the context of divestitures, this paper critically assesses different hypotheses from the corporate finance literature and establishes the main reasons responsible for the decisions.

The paper distils hypotheses from the corporate finance literature on divestitures and tests them in an empirical case that has implications for the evolution of European power markets. An innovative mixed methods approach facilitates the testing of different hypotheses that would not have been possible otherwise and strengthens confidence in the validity of the results. Qualitative research, interviews, descriptive statistics and event studies converge in rejecting drivers related to operations and management, biased investment and investor preferences and in confirming debt overhang and risk contamination as the main drivers.

The paper is structured as follows. Section 3.2 lays out the goal and contribution of this paper. Section 3.3 reviews the corporate finance literature and distils its main hypotheses and their relation to each other. Section 3.4 gives an overview of the methodology used. Section 3.5 summarizes the main hypotheses and results. Section 3.6 to 3.9 are each dedicated to testing one group of divestiture drivers: drivers related to operations and management, investing, financing and investor preferences. Section 3.10 concludes and section 3.11 suggests policy implications as well as ideas for further research.

3.2 Goal, contribution and case selection

3.2.1 Goal and relevance

The goal of this paper is to investigate why EON and RWE divested in 2016 and why their approach was at the same time very similar (they separated their business segments in exactly the same way) and very different (EON intended to keep renewables and grid infrastructure and spun off the rest, while RWE kept the conventional generation and trading).

Why do we care what was driving the two utility divestitures in Germany? World wide, electricity markets are transitioning from a fossil fuel- and nuclear-based power supply towards more renewables. The transition has major consequences on incumbent utilities and thereby on the existing electricity system as a whole. This is all the more important, as electricity is generally regarded as a basic good that should be reliably available to all. Affordable and reliable access to electricity is also a fundamental factor for private investment and thereby a country's economic wealth. Moreover, electricity markets have strong monopoly tendencies and state policies play an important role. For these reasons, researchers and policy makers should have a vital interest in understanding the problems and strategies of utilities in order to apply lessons learned in Germany to other countries on a similar path away from nuclear and fossils to more renewable electricity sources.

3.2.2 Contribution to the literature

This paper is part of the energy finance and policy literature dedicated to utilities. A growing number of articles analyse the impact of the energy transition on utilities. For example, Kawashima and Takeda (2012) analysed the effect of the Fukushima nuclear accident on utility stock prices; Koch and Bassen (2013) attempted to value the the carbon exposure of European utilities and Frei et al (2018) investigated changes in utilities' portfolios worldwide.

A number of studies (Annex and Typoltova 2018; Bontrup and Marquardt 2015) and academic articles (Helms et al 2014; Kungl and Geels 2018; Sen and Schickfus 2017; Ossenbrink et al 2019; Weber 2017) have specifically analysed German utilities.

The drivers of the EON-Uniper and RWE-Innogy divestitures, the two most radical restructurings by diversified electric utilities to date, have not been analysed in the academic literature so far. Bebb, Comello and Reichelstein (2017) provide an interesting account of the Innogy carve-out, but it being a teaching case, they leave room for interpretation and do not pin down the divestiture's drivers.

Moreover, one can also see the paper as case study of systemic risk in the energy sector. So far, systemic risk has been mainly investigated in the financial sector connected to the 2008 crisis (Tasca and Battiston 2016) or to stranded assets due to climate policy (Battiston et al 2017).

The paper's analysis contributes to the energy finance and policy literature. Moreover, it also offers a contribution to the corporate finance divestiture field: it distinguishes between outcomes and drivers of divestitures and systematises different divestiture drivers and corresponding testable indicators, thereby contributing to a more coherent framework for analysing divestitures.

3.2.3 Case selection

The selection of the German utility divestitures for a case study is justified for at least three reasons. First, it is a case fairly typical for many European countries: Germany's electricity system had long relied on conventional technologies like coal, natural gas and nuclear. Recently, policy makers had started pushing a transition to more renewables, just like in many European countries today. The German power sector is thus typical in its direction of change.

Yet, second, it is also extreme in its progressiveness and speed, as support policies for renewables were among the most generous worldwide and the nuclear exit one of the most ambitious. We should therefore observe typical effects of an energy transition, but more pronounced than we might in cases with moderate policies.

Third, EON and RWE are very similar utilities regarding their main segments, generation portfolios and business models. Being mainly active in Germany, they were exposed to the same market changes (see Appendix 3.13.1). One factor was different, though: RWE knew that policy makers

would not allow the nuclear segment being spun off. As a result, RWE's restructuring was different from EON in only one aspect, that is in what part of the company was carved out.
The cases of EON and RWE therefore combine three useful features described in the literature on case selection that make them particularly suitable to test: they are at the same time "typical", "extreme" and "most similar" as put forward by Seawright and Gerring (2008).

3.3 The divestiture literature

The goal of the literature review is to distil hypotheses that explain corporate divestitures. These hypotheses are subsequently used to examine the possible drivers of EON's and RWE's divestitures. Three main types of divestitures are distinguished in the literature. The asset sale is the sale of a subsidiary or other assets directly from one firm - the parent firm - to another firm. The spin-off is a pro-rata distribution of shares in a subsidiary to the existing shareholders of the parent firm. The equity carve-out is an initial public offering (IPO) of a subsidiary, i.e. the offering of shares in a subsidiary to the investment public (Weston et al 2004). EON used a spin-off whereas RWE did an equity carve-out.

3.3.1 Divestiture outcomes

3.3.1.1 Corporate focus

Research from the 1990s first noted a trend in divestitures towards fewer firm segments post-divestiture and a correlation of this increased focus with rising share prices and better operating performance (Comment and Jarrell 1995, John and Ofek 1995). It became common practice in the literature to regard corporate focus as a possible driver of divestitures, even though the reasons for why a lower number of firm segments might lead to better performance was often not analysed. This paper regards increased focus not as a driver, but as an outcome that might point to underlying drivers related to operations and management (section 3.3.2.1).

3.3.1.2 Access to funds

Access to funding is another explanation brought forward in the divestiture literature. This paper regards access to funding as an outcome as well, rather than a driver, for a driver would need to explain why a firm incurs the costs of restructuring as opposed to simply raising more debt or equity. It would need to explain why money raised through the divestiture directly (asset sale or equity carve-out) or later as capital taken up by the new subsidiary or the rump parent company (spin-off or equity carve-out) is cheaper than capital raised in the original parent firm.

The access-to-funds topic has been distinguished in two ways in the literature. The first possibility is that the divestiture decreases the firm's higher-than-average debt either by using the proceeds directly to retire debt and thereby reducing financial distress (Brown, James and Mooradian 1994; Lang, Poulsen and Stulz 1995) or by transferring debt to their subsidiary (Desai and Jain 1999). This outcome would hint at debt overhang being a main driver (section 3.3.2.3).

The second possibility is that the goal is to raise funds for growth in the subsidiary (Schipper and Smith 1986; Daley, Mehrotra and Sivakumar 1997; Vijh 2002).[1] This outcome could hint at a number of drivers, which would need to explain why growth opportunities cannot be funded in the integrated firm, e.g. debt overhang, agency conflicts related to investing or risk contamination (see also table 3.1).

3.3.2 Divestiture drivers

Drivers are divided into four groups: operations and management, investing, financing and investor preferences.

3.3.2.1 Drivers related to operations and management

The first group of drivers refers to the relationship of the firm's operations to each other and to the managers. Authors generally use poor performance pre- and better performance post-divestiture to argue for these drivers.

Inefficient diversification. The inefficient diversification argument suggests that managers previously diversified inefficiently, driven by agency problems like empire building (Jensen 1986, 1988), hubris (Roll 1986), managerial entrenchment (Shleifer and Vishny 1989) or managerial discretion (Stulz 1990, see also section 3.3.2.2).

Change in synergies. Similarly, a change in synergies between business segments might also lead to poor performance and drive firms to divest (Hanson and Song 2003). Reasons for changes in synergies might be changes in regulations or technical innovations (Shleifer and Vishny 1990; Kaplan and Weisbach 1992).

Lack of fit with owner or better fit with buyer. Another driver of divestitures might be a better fit with the buyer's skill set (John and Ofek 1995; Daley, Mehrotra and Sivakumar 1997).

[1] This holds only for equity carve-outs, where funds are raised immediately, and for spin-offs, where funds can be raised later in the separate firm, but not for asset sales, where the subsidiary does not become a separate entity.

Management focus. Even if the skill sets of managers in subsidiary and rump parent firm are not so different, one could argue that simply the reduction of the diversity of segments under management increases the efficiency of the managers (Berger and Ofek 1995; Desai and Jain 1999).

3.3.2.2 Drivers related to investing

The second group of drivers is related to suboptimal investment decisions by the management in the integrated pre-divestiture firm, be it at headquarters or in the divisions. Suboptimal investments are caused by some type of agency conflict between managers and shareholders. The result is a 'pecking order' in the sense of Myers (1984), where proceeds from a divestiture or capital raised in the post-divestiture firms are cheaper than new equity or debt in the integrated firm. Lang, Poulsen and Stulz (1995) first referred to this in the context of divestitures.

Asset substitution. This driver refers to the danger of managers being pushed into high risk projects by shareholders at the expense of debt holders, as shareholders have unlimited upside but limited downside risk. The mechanism was first discussed by Jensen and Meckling (1976). Lang, Poulsen and Stulz (1995) and Officer (2007) mention it as a potential driver for divestitures, albeit without going into detail.

Managerial discretion. This is another agency problem causing less than optimal investments. The argument was first developed by Jensen (1986). Due to personal benefits linked to investments, managers always claim that cash flow is too low to fund all positive net present value (NPV) projects. Their claim is therefore not credible when cash flow is truly low. The result is a situation of under-investment when cash flow is low and over-investment when it is high, as capital markets price in the agency conflict (Stulz 1990). Divestiture might therefore be a cheaper way to raise funds directly than on the capital markets.

Rent-seeking by divisions. Another explanation for suboptimal investment in the integrated firm is a failure to optimally allocate capital to different divisions. Meyer, Milgrom, and Roberts (1992), Wulf (1997) and Scharfstein and Stein (2000) theoretically model how rent-seeking by the divisions can induce corporate headquarters to allocate excessive capital to divisions with poor investment opportunities. Empirically, Lamont (1997), Shin and Stulz (1998), Scharfstein (1998) and Rajan et al (2000), among others, have shown that conglomerate divisions might receive cross-subsidies, that is more funds than is justified by their own cash flows or by their growth opportunities. In the empirical divestiture literature, Dittmar and Shivdasani (2001) find that after asset sales parents' investment allocation improves. Gertner, Power and Scharfstein (2002) find that spun-off subsidiaries optimize their capital allocation.

Failure of capital allocation method. A recent stream in the literature relates to the failure of companies to adequately reflect the risk-return profile of different projects in their capital allocation method. Krüger et al (2015) argue that, controlling for growth opportunities, companies are inclined to invest less in their low-risk divisions because they use one single cost of capital to appraise projects across segments. Helms, Salm and Wüstenhagen (2014) have applied the same argument to utilities' investment behaviour.

3.3.2.3 Drivers related to financing

The last group of drivers analyses the effect of financing decisions in an integrated compared to a separated firm. While most drivers assume an effect of financing on investment incentives, appropriate gearing and the risk contamination effect can be explained through purely financial effects keeping investment constant.

Debt overhang. Debt overhang describes a situation where a positive NPV project cannot be funded by either debt or equity, because the project returns would partly benefit existing creditors (Myers 1977). This might explain why asset sales can be attractive: the proceeds might be cheaper than new debt or equity. And the firm could use the funds to retire debt, thereby alleviating debt overhang. The problem is mentioned by Lang, Poulsen and Stulz (1995) and Hanson and Song (2003) in the divestiture context and high leverage is generally used as an indicator for poor financing options of divesting firms (see section 3.3.1.2). For spin-offs, Desai and Jain (1999) hypothesise that the firm could get rid of some debt by transferring it to the new subsidiary.

Appropriate gearing. Some authors argue that the debt overhang problem can be less severe for separate as opposed to integrated firms. For example, Myers (1977) observes that depending on the joint cash flows and existing debt, either separate or joint financing can lead to better investment incentives. John (1993) models spin-offs and shows that when divisional cash flows are positively correlated, spin-offs can lead to value increases: the "intuition is that for sufficiently high debt levels on the parent firm, there is a lock-up effect such that the technologies are either exercised together or neither is exercised. The flexibility afforded by optimally allocating the debt between components improves investment incentives." (John 1993, p. 139)
Leland (2007) relies on purely financial effects to develop the appropriate gearing hypothesis, i.e. investment stays constant. He assumes an optimal debt level in the trade-off theory sense: the benefit of a debt-related tax shield is balanced against the increase in bankruptcy cost with higher debt levels. Depending on whether a divestiture increases or decreases the overall tax shield in the two henceforth separate firms taken together, there is thus a positive or negative effect from appropriate gearing after divestiture (Leland 2007).

Risk contamination. The risk contamination argument constitutes the other half of Leland's model and it is an unambiguously positive financial effect of separation. It is essentially the downside of the co-insurance effect: divisions can co-insure each other, but they can also contaminate each other. Specifically, if divisions' cash flows can be negative, one division can eat into another one's cash flows or even assets (Scott 1977; Sarig 1985). In a separated structure, one division's losses are limited by the same division's assets with no effects on other divisions. Leland (2007) calls this the 'limited liability (LL) effect' of separation. His model predicts that the benefits of separation increase in segments' cash flows correlation and with high or very different volatilities or default costs. Banal-Estanol, Ottaviani and Winton (2013) extend the analysis to show that also without the 'appropriate gearing' aspect, i.e. when holding total debt constant, the net of LL and co-insurance effect can justify separation.

Asymmetric information. The asymmetric information hypothesis goes back to a paper by Myers and Majluf (1984) that inspired the development of the pecking order theory of capital structure. Managers know the true value of the firm's assets and growth opportunities whereas outside investors can only guess. Acting in the interest of existing shareholders, managers cannot issue new stock for all positive NPV projects because equity issues signal the firm being overvalued by the market. They thus prefer internal funds to debt and debt to equity. Nanda (1991) extends the model and explains why equity carve-outs on average have a positive effect on the parent's share price, contrary to seasoned equity offerings. His model is, however, not applicable to EON or RWE.[2]
Another mechanism related to asymmetric information is simply the reduction of information asymmetry by going public (Schipper and Smith 1986). Several researchers have examined this by looking at analysts' forecast dispersion or error or the increase in coverage by analysts post-divestiture (Best, Best and Agapos 1998; Krishnaswami and Subramaniam 1999; Gilson et al 2001; Chen and Guo 2005).

3.3.2.4 Drivers related to investor preferences

The last driver rests on the assumption that investors have heterogeneous preferences and that spin-offs and equity carve-outs facilitate the trading in different stocks than pre-divestiture. Value creation might thus stem from relaxing a trading constraint that existed previously.
Vijh (1994) finds increased trading volume and abnormal positive stock returns on the day that the subsidiary starts trading separately. Were value gains related to the parent firm only, one would expect share price improvements taking place on the announcement day of the splits and the ex

[2]Nanda's model is only applicable to divestitures with immediate funds being raised, thus not to EON. The model hinges on the assumption that the subsidiary is smaller than the parent so that the positive share price effect of the parent's being undervalued dominates. Innogy, however, is more than 40% larger in terms of book asset value and market cap than its parent RWE ex Innogy.

date not having any significant effect. Excluding measurement errors and arbitrage, Vijh, similar to a later paper by Chemmanur and He (2017), concludes that heterogeneous preferences must be driving the share price gains on the ex date.

Shunning of sin stocks. One way to explain investor preferences would be the shunning of sin stocks. Hong and Kacperczyk (2009) provide evidence that ethical norms restrict holding of firms involved in alcohol, tobacco and gaming by certain institutional investors, leading these stocks to trade at a premium.

Search for yield. The low interest rate environment of the last years is another possible driver of investors' demand for certain stocks and corporate bonds as an alternative to zero or negative interest sovereign bonds. Renewable energy assets, for example, have been discussed in the industry as assets with potentially "strong long-term growth potential with low correlation to other asset classes, while also providing stable cash flows and meaningful dividend yields" (Allianz 2017, p. 1; Ernst & Young 2014).

3.4 Methodology

The paper uses an innovative mixed methods approach. This facilitates the testing of different hypotheses that would not have been possible otherwise. Even though different methods might command different degrees of confidence in the results, all hypotheses have been tested with several methods and the main and most complex driver argued for in this paper has been tested using a share price event study, among other methods. This strengthens confidence in the validity of the results. As described in more detail in section 3.5, qualitative research, interviews, descriptive statistics and event studies converge in rejecting drivers related to operations and management, biased investment and investor preferences and in confirming debt overhang and risk contamination as the main drivers.

1. **Comparative descriptive statistics**: Relying on the Stoxx 600 Europe Utilities index, two control groups of other listed European utilities were established: one containing all other 24 utilities on the index, the other only those nine that were similar in products, markets and shareholders to EON and RWE. The method for obtaining the control groups is described in appendix 3.13.2. Indicators that were distilled from the divestiture literature are then plotted for EON and RWE and compared to the control groups. Given that no other European utility restructured in a similarly important way, stark differences between EON and RWE as opposed to the control groups might be taken as evidence for certain divestiture drivers. On

the other hand, if EON and RWE were very similar to their control groups in certain indicators, this might be evidence against these drivers.[3]

2. **Interviews**: in the course of 2018, 20 interviews were conducted to triangulate the other methods. The interviewees were 10 people who worked at EON or RWE in 2016, of which two and three were from management, and three and two from staff at EON and RWE respectively. Ten were experts, of which three equity analysts, three financial news journalists, two from management at two other European utilities and two academics. The clear focus of the responses on a couple of drivers turned out to be in line with the rest of the analysis.

   All interviews were done in a semi-structured way and started from the question: "What do you think were the main drivers responsible for the splits of EON and RWE in 2016?" so as to not bias the responses initially. In the course of the interview, all possible drivers identified were then offered as potential alternative explanations.

3. **Analysis of gray literature**: EON and RWE annual reports (2005-2017), investor presentations, and more than 280 newspaper articles have been analysed in order to enrich and triangulate the results of the other methods.

4. **Share price event study**: While comparative descriptive statistics, interviews and the analysis of gray literature are used to test all hypotheses, the event studies are only used to investigate two hypotheses that were most referred to in the interviews: risk contamination and investor preferences. Using regression analyses, the effect of different events on EON's and RWE's share price and stocks traded is examined. The tests are used to examine whether certain types of new information were perceived as a risk for the utilities' future growth options in line with the risk contamination hypothesis developed earlier and whether the ex dates had an effect on trading indicating evidence for heterogeneous investor preferences.

3.5 Indicators and summary of results

3.5.1 Indicators and interview results

Table 3.1 lists the possible drivers with empirical indicators identified from the literature as well as the methods used to test them. The drivers related to operating and management are all summarized into one column, as well as the drivers related to investing and investor preferences, whereas the financial drivers are listed separately because their distinction will be important later on. The

[3] Vattenfall and EnBW, even though they own the third and fourth biggest generation portfolio in Germany, are not part of the control group. They are dominated by public shareholders holding more than 95% and are thus not part of the Stoxx index.

cells are only filled if the corresponding hypothesis predicts the indicator to be confirmed. Indicators that are confirmed are marked with yes and rejected with no. The last line states whether sufficient evidence could be gathered for each driver. Only if all of the relevant indicators are confirmed, evidence is deemed sufficient to confirm a driver. Drivers are rejected if at least one indicator is marked with no. Only debt overhang (III.1.) and risk contamination (III.4.) are confirmed; all other drivers are rejected.

Table 3.2 shows the number of interview partners supporting each hypothesis. For anonymity reasons the results cannot be distinguished any further, but there were no trends evident in responses from different sub-groups. Interview results strongly concentrate on two drivers: risk contamination (III.4.) and investor preferences (IV., total support of 15 and 16).

Indicator	Method used	**I.Operations and management**	**II.Investing**	**III.1.Financing: debt overhang**	**III.2.Financing: appropriate gearing**	**III.3.Financing: asymmetric information**	**III.4.Financing: risk contamination**	**IV.Investor preferences**
Low performance pre-, better post-divestiture	Comparative descriptive statistics	Yes	Yes	Yes			Yes	
Increase in focus	Gray literature, interviews	Yes						
Changes in synergies pre-divestiture	Interviews, gray literature	No						
New managers with different skill sets	Interviews, gray literature	No						
Funds raised for growth	Comparative descriptive statistics, gray literature		Yes	Yes			Yes	
Funds raised for retirement of debt	Comparative descriptive statistics, gray literature			Yes				
High overall capex/assets	Comparative descriptive statistics		No					
High correlation capex with cash flows	Comparative descriptive statistics		No					
Low capex in renewables vs. conventional	Capex numbers from annual reports		No					
One cost of capital used for all segments	Interviews		No					
High leverage	Comparative descriptive statistics			Only if incl. nuclear provisions				
Higher tax shield post-divestiture	Tax shield				No			
Improved earning estimates post-divestiture	Analysts' estimates from Bloomberg					Only at RWE's Innogy		
Different valuations parent vs. subsidiary	Valuations from Thomson Reuters						Yes	
Big past and risk of future losses in one part of firm	Comparative descriptive statistics, interviews, event studies						Yes	
Share price effect on ex date	Event studies							Only on RWE-Innogy ex date
Investor preference for renewables and grids over conventional generation	Interviews, gray literature							Possibly but unclear if loss avoidance
Divestments due to political commitments	Interviews, gray literature, data on shareholdings							No
Driver confirmed?		**No**	**No**	**Yes**	**No**	**No**	**Yes**	**No**

Table 3.1: Hypotheses with main indicators tested in this paper. Indicators that are confirmed are marked with yes, undecided with unclear and rejected with no. Cells are empty for indicators not relevant for the respective hypotheses. The last line summarizes the overall result for each driver tested.

	Experts	EON	RWE	**Total**
Total number of interviewees	10	5	5	**20**
Drivers related to operations and management[4]	3-2	4-1	1-1	**8-4**
Drivers related to investing	1	1		**2**
Drivers related to financing: debt overhang	2			**2**
Drivers related to financing: appropriate gearing	1	1		**2**
Drivers related to financing: asymmetric information	1			**1**
Drivers related to financing: risk contamination	8	4	3	**15**
Drivers related to investor preferences	7	5	4	**16**

Table 3.2: Number of interviewees supporting each driver.

3.5.2 Summary of results

The results of the different methods converge in identifying debt overhang and risk contamination as the main drivers. Investor preferences was argued for as a driver by many interviewees, but the analysis could not distinguish the argument sufficiently from the risk contamination driver.

The rest of the paper succinctly analyses each driver with the help of the described methods and indicators. Most detail is dedicated to risk contamination, as it is the most complex and the main driver argued for in this case study.

3.6 Drivers related to operations and management

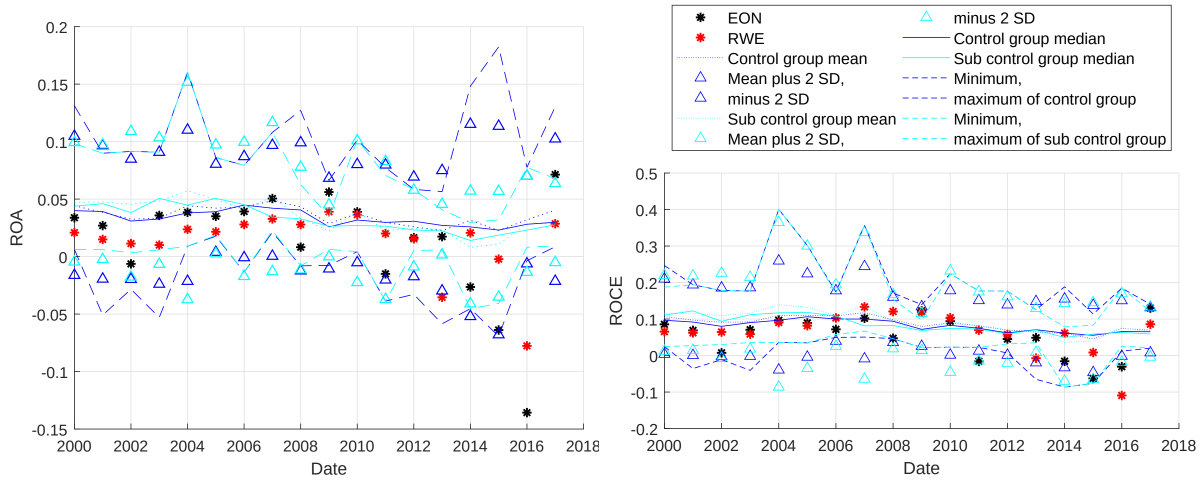
3.6.1 Poor performance before and better after divestiture

Poor performance pre-divestiture and a recovery afterwards is an indicator commonly linked to operations and management, investing or financing related drivers (table 3.1). Starting in 2013 or 2015, depending on the control group used, return on assets (ROA) and return on capital employed (ROCE) of the two utilities indeed fell out of the range of the control groups' minimums and the average minus two standard deviations. After the divestitures, in 2017, performance seems to have recovered (figure 3.6.1).

Performance thus seems to have recovered post-divestiture, which might point to either operations and management, investing or financing related drivers.

3.6.2 Inefficient diversification, change in synergies, better fit with new managers' skills or management focus?

Most interviewees judged the increase in focus, with portfolios comprising conventional generation and trading on the one hand and renewables and grid infrastructure on the other, positively. Nobody argued that the managers of the new companies had any specialised skill sets. In fact, in 2017, most managers at EON, RWE, Uniper and Innogy came from within EON's and RWE's non-



(a) Return on assets (ROA).
Calculated by net income over total assets.

(b) Return on capital employed (ROCE).
Calculated by EBIT over (total assets less current liabilities).

Figure 3.6.1: Indicators for performance. Source: Own calculation based on Thomson Reuters Datastream.

renewable business units.[5] One can thus not argue that managers' specialised skill sets were a driver.

Instead of emphasizing skills, interviewees mentioned the potentially positive effect of a smaller range of tasks for management to focus on. One RWE executive said: "We face big changes in the industry - for example the development of smart infrastructure, the electrification of car transport, the self production of electricity. RWE could concentrate only on power generation, and Innogy on decentralised innovation." (Interview 16)

On the other hand, cost savings were not in the focus and a number of interviewees claimed significant costs incurred in terms of synergies lost, which are marked with negative numbers in table 3.2. For example, Uniper had taken over EON's trading section. "But then EON faced the challenge of procuring electricity for their retail segment, and selling their renewable electricity. So they opened another trading desk at EON." (Interview 12) An RWE manager said: "There were certainly synergies lost and these were quantified before the split decision. For example, if you have your own retail segment, this can hedge your electricity generation, as forward contracts are only liquid about three years into the future. Also, there are significant overhead costs for having two headquarters." (Interview 16)

In contrast, interviewees praised the intelligent synergistic decision of the later EON-RWE asset swap, a second spectacular turnaround, announced in February 2018. Interviewees argued that this swap would result in substantial cost savings for both utilities in contrast to the 2016 splits

[5] Out of 17 managers at EON, RWE, Uniper and Innogy, 14 had a career background in the conventional energy business. 13 managers held positions at the respective parent firms EON or RWE prior to the split. Four managers held outside positions, of which two where in the conventional energy business and two in IT-related roles. Only one manager at Innogy had a specialised background in renewable energies, albeit also acquired in-house at RWE (EON, RWE, Uniper, Innogy 2017).

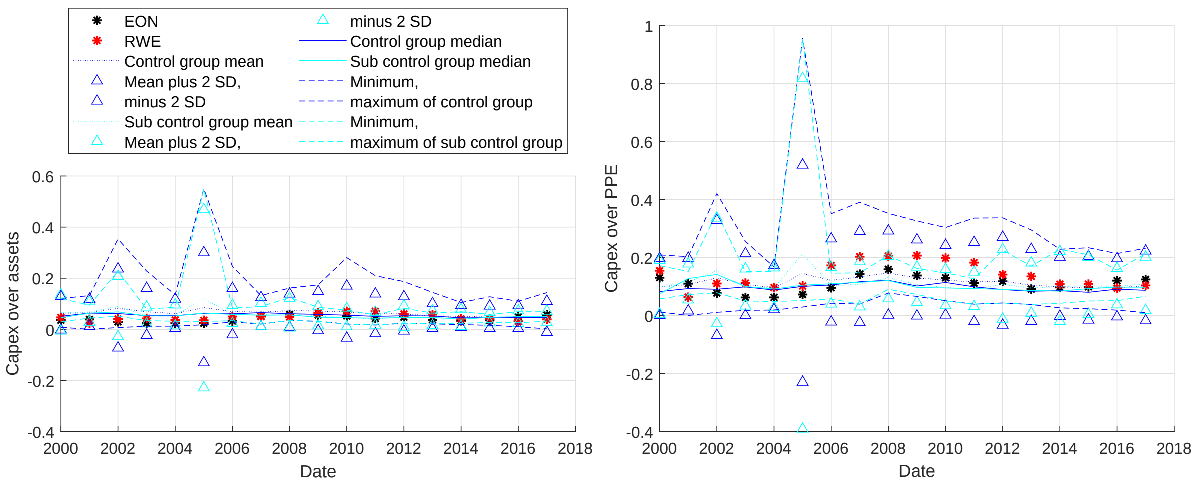
(Interview 9, 11).

In summary, there might be a benefit of having a smaller range of tasks; however, none of the other operational and management related indicators could be confirmed. In fact, for synergy reasons, a different segment separation would have been more efficient and there even seem to be substantial dis-synergies of the 2016 divestitures. This is why operational and management drivers are rejected.

3.7 Drivers related to investing

3.7.1 Over-investment due to asset substitution or managerial discretion

To confirm distortions related to investing due to agency conflicts, the literature has commonly used capital expenditure (capex) relative to assets or correlated with cash flows (e.g. Lamont 1997; Andrade and Kaplan 1998; Scharfstein 1998; Shin and Stulz 1998; Gertner, Power and Scharfstein 2002; Eisdorfer 2008). We compare capex over total assets, over property, plant and equipment (PPE) and correlated with cash flows for EON and RWE and our control groups. If managers over-invested due to agency problems like asset substitution or managerial discretion, we would expect higher than average capex and higher correlation of capex with cash flows.



(a) Capital expenditure over total assets.

(b) Capital expenditure over property, plant and equipment.

Figure 3.7.1: Indicators for total capital expenditure. Source: Own calculation based on Thomson Reuters Datastream.

The figures reveal that investment was in line with both control groups except for capex on PPE at RWE pre-2012. The correlation coefficient of capex with cash flows from 2000 to 2017 is only moderate and even lower at EON and RWE than in the control groups: 0.46 for EON; 0.41 for RWE; 0.68 for all utilities. The result is robust to taking the more recent period from 2005 to 2014, which is possibly more relevant for the divestitures, and to looking at operating cash flows only (see also appendix 3.13.3).

The overall numbers thus do not provide sufficient evidence for higher than average agency conflicts at EON and RWE.

3.7.2 Distorted investment due to rent-seeking or a biased capital allocation method

Next, we test for cross-segment subsidization due to rent-seeking or a biased capital allocation method. As renewables became a growth market and conventional generation was forced out of the market, if there were no distortions, one would expect investment to shift from conventional generation towards renewables at EON and RWE.

Most data for this section is taken from EON's and RWE's reporting only, because segment reporting is not comparable across all Stoxx utilities.

Pre-2009/10, segment reporting on renewables is not available, but the existing literature (e.g. Kungl 2018) and interviewees point at decisions not being taken optimally. An equity analyst: "Between 2000 and 2005 the utilities had a fat harvest. They ignored renewable energy. They found the sector suspicious because it still needed subsidies. Coal was cheap, nuclear was profitable. So they were blind to anything new. They entered the renewables business too late." (Interview 14)

Interviewees also emphasized that the capital allocation method at the time fostered a bias toward the existing conventional segments. Both RWE and EON had allocated capital by adjusting discount rates according to segment, technology and country risk (Interview 6, 16, 19). The claim by Krüger et al (2015) that investment distortions occur simply due to the usage of one single cost of capital in the entire firm does not hold in this case. Rather, the pressures from powerful divisions might have biased assumptions and thereby indirectly affected discount rates. For example at RWE, "it was a political bazaar. Everyone knew that the assets are very long-lived. So if you wanted more funds for your segment, it could help if you pushed certain assumptions about the long-term trend of power prices." (Interview 7). At EON, it was "every business segment for itself. [...] Every segment said we need amount X. Then the negotiation ensued. Now, on the contrary, strategy and management decide on an overall number for each segment and the segments only decide on the allocation between projects." An EON manager thought that before the reform in capital budgeting, "we might have given high risk projects to much money, because we did not price the risks accordingly. Sometimes it was also the division managers that were screaming the loudest, who got the most of the funds." (Interview 6) Interestingly, EON reformed the capital allocation method towards a more top-down approach in 2017, that is after the Uniper spin-off. In fact, none of the interviewees connected the splits in 2016 to problems in capital allocation.

Moreover, even though EON and RWE probably initially under-invested in renewables, other utilities that did not restructure under-invested on a similar scale: figure 3.7.2 shows that EON's and

RWE's renewables share is a little below the mean but in line with the median of the control groups.

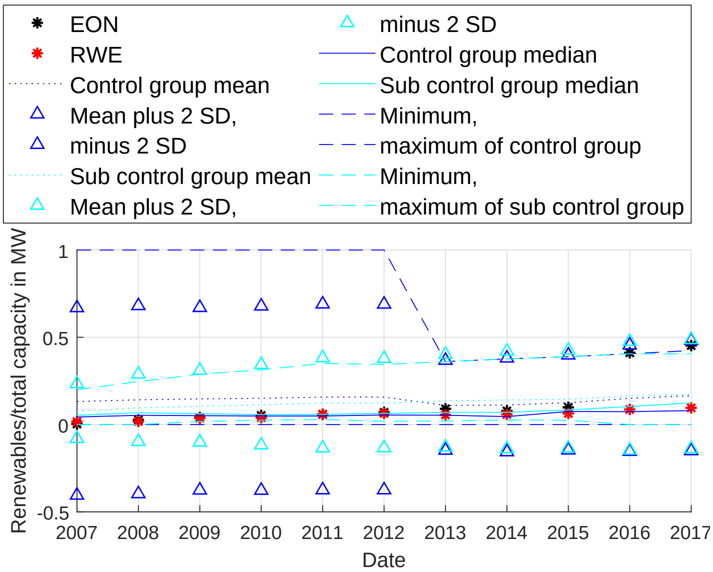


Figure 3.7.2: Renewables capacity in MW over total capacity.

Between 2010 and 2016 total capital expenditure at EON and RWE starkly decreased (see figure 3.7.3). Investments in the conventional sector took the largest cuts: EON's investment in its 'generation' segment decreased by 78% between 2010 and 2015 and RWE's 'conventional power generation' by 81% between 2012 and 2016. Investment in German electricity distribution grids and sales did not show any consistent trend. Investment in renewables at EON showed a peak in 2012 and then declined. At RWE, renewables capex almost tripled between 2008 and 2013, but in 2015 collapsed to less than half, following the overall declining capex trend.

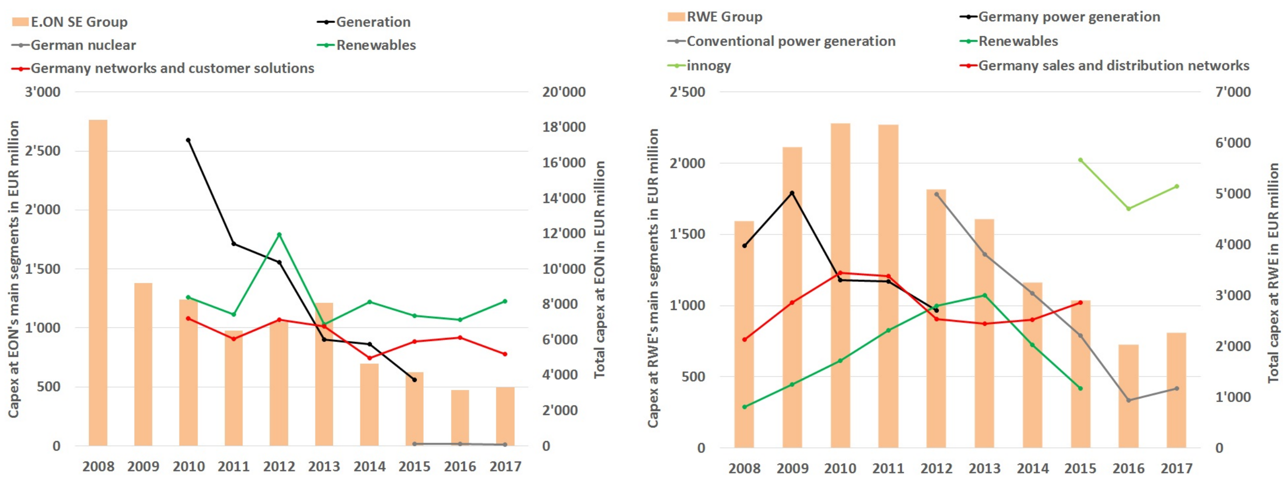


Figure 3.7.3: Capital expenditure on intangible assets, property, plant and equipment and investment property in EON's and RWE's main segments in EUR million. Source: Own illustration based on EON and RWE annual reports.

Appendix 3.13.3 shows segment capex over different measures of segment profitability and size. What stands out are the high capex ratios in the renewables segments. Even though investment in renewables did not increase or even decreased in absolute terms post-2010, measured by profitability and segment size it still received a higher share of investments than the overall firm and conventional generation. This means that utilities had acknowledged renewables as a growth market. After being hit by declining profits, they mainly reduced investing in conventional generation, but they eventually had to cut spending in renewables, too.

This is all the more understandable, since renewables were still free-cash-flow negative until around 2014 for various reasons (EON and RWE 2005-2014),[6] while parts of the conventional fleet, such as the remaining nuclear power plants, were still profitable. Furthermore, returns in the conventional segments were not continuous: "In conventional energy production, we had to undertake some investments because of path dependencies" said one senior staff at RWE (Interview 7). RWE's CFO Bernhard Günther, when asked about why RWE would not close its conventional power plants more pro-actively, said that "lignite is a complex system where you cannot close individual plants so easily," hinting at the scale effects of operating German lignite power plants at full capacity close to the lignite mines (RWE 2016-03-08). Similarly, in a 2013 EON presentation to investors, management had justified investments in conventional and distribution assets by calling them "maintenance capex" that are "necessary to maintain existing assets in operation", "necessary to keep [the] license to operate" and "inflexible: to significantly reduce capex [we] would have to exit [the] business altogether". EON management announced that "discretionary capex" would by "2015 almost completely [be] allocated to priority growth areas: renewable energy, distributed energy, outside Europe" (EON CMD 2013).

Thus from around 2010, there were path dependencies in investing, but no systematic bias disadvantaging renewable energies due to agency conflicts, rent-seeking or a biased allocation method, which is why drivers related to investing are rejected. Thus the question is rather why the firms could apparently not raise additional debt or equity to invest into more growth in renewables.

3.8 Drivers related to financing

3.8.1 Debt overhang

This section examines whether, in accordance with debt overhang, EON and RWE raised funds for growth or the retirement of debt and whether they had higher leverage prior to the divestiture as compared to their non-divesting peer group.

[6]See also appendix 3.13.4. The reason why the renewables segments were still losing money in 2013 and 2014 is subject to debate in the literature and among practitioners. Factors might have been long lead times of offshore wind projects (Interview 12), delays in grid access of offshore parks (Spiegel 2011), unforeseen cuts in renewable electricity tariffs in Spain and the Netherlands (EON 2013, RWE 2013) as well as the planned scaling down of subsidies in Germany (Interview 6). Some interviewees also blamed a lack of experience in renewable technologies paired with the pressure to invest at any cost to make up for lost time at the utilities (e.g. Interview 16).

3.8.1.1 Funds raised for growth and retirement of debt

Raising funds through divestitures could hint at different drivers: biased investment, risk contamination or debt overhang (see table 3.1).

EON did not raise funds when Uniper had its stock market listing in September 2016, but funding was accessed later: in March 2017, the new EON raised EUR 1.35 billion through a capital increase. This was used to partly fund the contribution to the public nuclear fund (see section 3.8.4). In June 2018, EON finalized the sale of its 46.65% stake in Uniper to its competitor Fortum for EUR 3.8 billion. EON stated that the proceeds would be used to fund growth in renewables and networks (EON 2018).

In October 2016, RWE sold 73.4 million shares of its holding of its subsidiary Innogy and another 55.6 million were placed through a capital increase by Innogy at the same time. RWE's stake in Innogy dropped to 76.8% as a result. RWE also announced that it would use the EUR 2.6 billion from the sale of Innogy shares to fund its share in the nuclear fund, while the 2 billion from Innogy's capital increase were intended for growth projects in renewables and networks (RWE 2016).

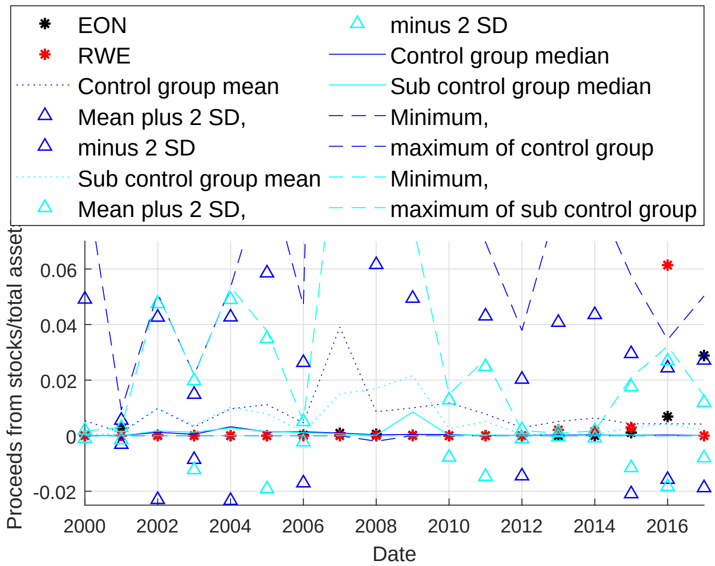


Figure 3.8.1: Proceeds from issuing stocks over total assets for different utilities. Source: Own calculation based on Thomson Reuters Datastream.

Figure 3.8.1 shows proceeds from stocks raised by EON and RWE over assets compared to the control groups. It shows very low issuance until 2015 and a spike compared to the control group for RWE in 2016 and for EON in 2017.[7]

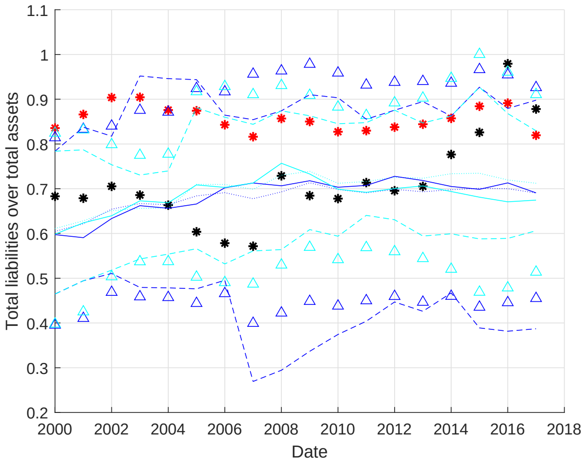
RWE and EON thus had raised a considerable amount of funds directly and indirectly through the divestitures. They stated that they would invest the funds in growth and also retire debt, insofar as the nuclear funds contributions can be classified as debt.

[7] In the late 2000s, a few utilities had pursued a similar strategy to RWE, which leads to high standard deviations during that time. EDF floated its renewable subsidiary in 2006, which was followed by Iberdrola in 2007, EDP in 2008 and Enel in 2010. All intended to use the funds for growth and bought back the minority shares later.

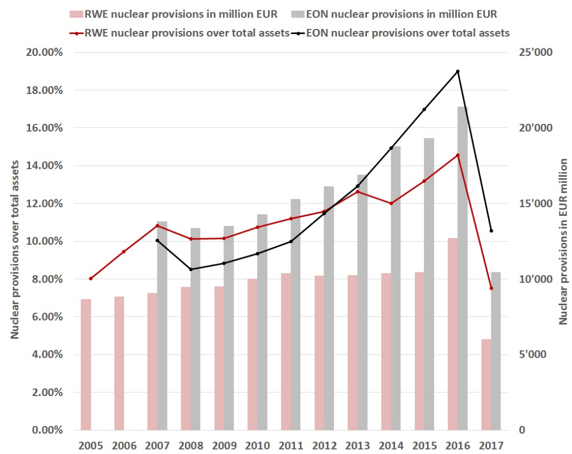
3.8.1.2 High leverage

Concerning long-term bond ratings, European utilities suffered from a wave of downgrades. Between 2005 and 2017 their average rating deteriorated from A+ to between A- and BBB+. EON's and RWE's ratings decreased in line with that. Debt and liquidity indicators were also in line with control groups; EON and RWE net debt and long-term debt were even lower than average in the recent years (see appendix 3.13.5).

When looking at total liabilities over assets, the picture is different, however (see figure 3.8.2): EON's liabilities increased noticeably and RWE's increased slightly from a very high level between 2013 and 2015. The reason is that total liabilities include provisions for nuclear dismantling and storage, whereas debt does not. Between 2007 and 2015 nuclear provisions increased by 40 and 16% in absolute terms and by 69 and 22% relative to total assets at EON and RWE respectively.[8]



(a) Total liabilities over total assets. EON black, RWE red, control groups blue (for full legend see previous graph).



(b) Nuclear provisions in EUR million and over total assets.

Figure 3.8.2: Nuclear provisions and overall liabilities. Source: Own calculation based on Thomson Reuters Datastream and EON and RWE annual reports.

There is thus strong evidence for the debt overhang hypothesis - but only if one counts nuclear liabilities towards debt.

3.8.2 Appropriate gearing

The idea of appropriate gearing is that, by splitting up, the tax shield of debt increases due to the possibility to adjust debt levels more appropriately to the two henceforth separate firms. This has been argued for EON, for example, in J.P. Morgan's equity analyst report (Casali 2015).

In 2017 interest over assets and interest times tax rate over assets at EON and RWE was very close

[8]For 2016 and 2017 ratios, total assets are calculated by still assuming the integrated company. As EON does not consolidate its Uniper holding, EON cum Uniper assets = EON assets + Uniper assets. Since RWE fully consolidates its Innogy holding, RWE cum Innogy assets = RWE assets + Innogy assets - RWE majority holding in Innogy assets of 76.8%. This is to avoid an exaggeration of the ratio due to the decreased asset base post-divestiture.

to or even lower than in 2015 (figure 3.8.3). This means that the overall tax shield did not increase in response to the divestiture and the appropriate gearing hypothesis can be rejected.

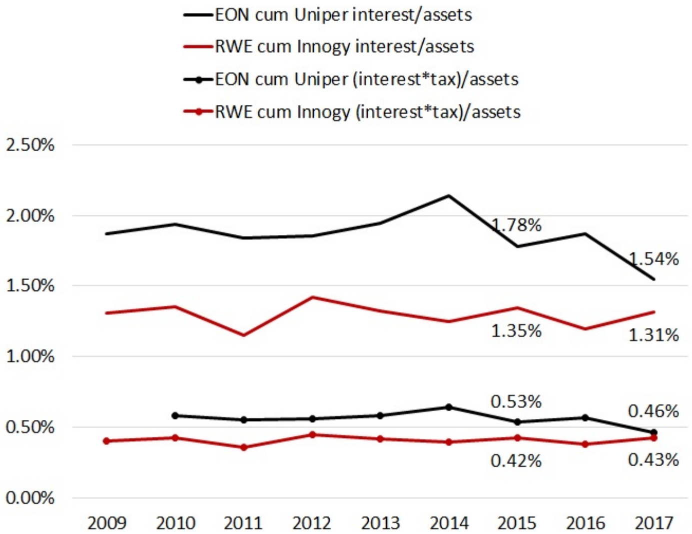


Figure 3.8.3: Interest over assets and interest times tax rate over assets. Source: Own calculation based on EON and RWE annual reports.

3.8.3 Asymmetric information

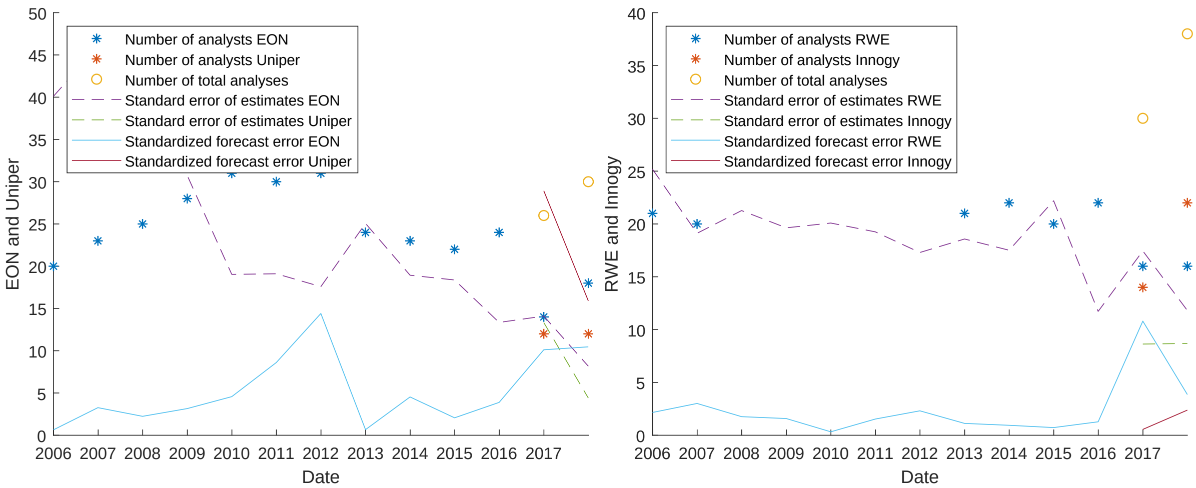


Figure 3.8.4: Analysts' coverage, standard errors and standardized forecast errors for EON, Uniper, RWE and Innogy. The standard error of estimates is calculated as the standard deviation of estimates/number of analysts and the standardized forecast error by the |mean EBITDA estimate - historical EBITDA|/standard deviation of the estimates.

Authors have argued that going public reduces asymmetric information or that information asymmetries are less relevant for one part of the firm leading to a better understanding and valuation of the separate firms. We search for a possible decrease in analysts' forecast dispersion or error or an increase in coverage by analysts post-divestiture.

There was indeed an increase in total coverage by analysts of EON cum Uniper and RWE cum

Innogy (figure 3.8.4). This, however, did not translate into a better EBITDA estimate or less dispersion in 2016 and 2017 for EON and RWE: standard errors of estimates and standardized forecast errors increased for both. Uniper's estimate has a lower standard error but higher forecast error than EON. Innogy has both lower standard error and standardized forecast error than RWE. Asymmetric information might thus have been lower only for Innogy as compared to RWE.
Why could it have been easier for analysts to value Innogy? In the next section it will be argued that RWE, EON and Uniper were to a certain extent risk-contaminated by the conventional generation portfolio.

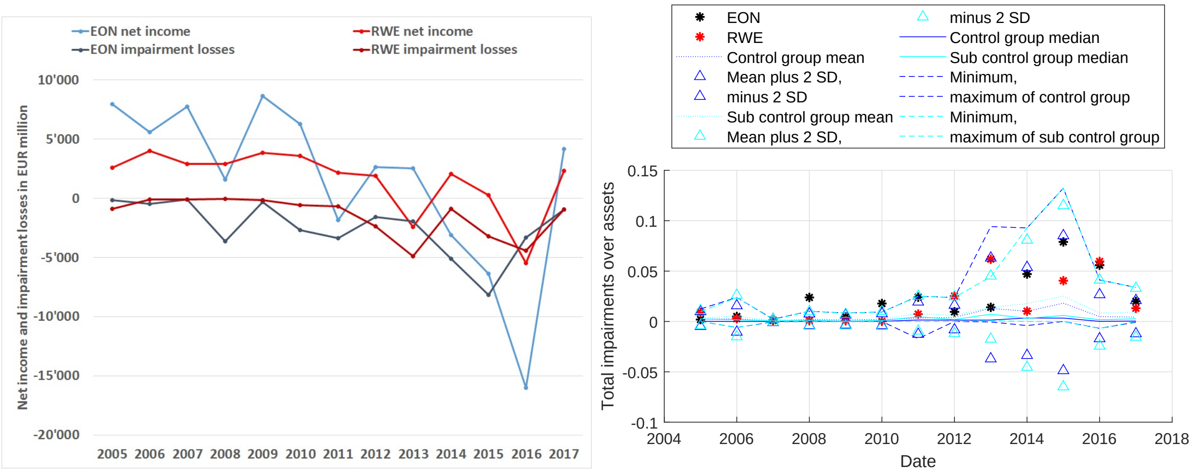
3.8.4 Risk contamination

The test of the risk contamination hypothesis consists of four parts. First, the origin of the profit decline at EON and RWE is examined. If past losses are an indication of future expected losses, then the risk contamination argument only makes sense if divestitures are structured such that the risky segments are shielded off. Second, stock market valuations of the pre- and post divestiture utilities are compared over time and to their peer group. If risk contamination was a driver, one would expect large valuation differences between parents and subsidiaries and an overall valuation increase post-divestiture. Third, a share price event study is conducted in order to find further possible reasons for risk contamination. Fourth, interview results are used for triangulation.

3.8.4.1 Sources of profit decline

Net income at EON and RWE closely followed losses from impairments. Impairments over book asset value increased from around 2011 to above average or median, but still below the control groups' maximums (see figure 3.8.5). EON wrote off EUR 20 billion between 2011 and 2015, or 13% of 2011 book asset value. At RWE, EUR 17 billion, or 19% of their 2011 book asset value were written off (EON, RWE 2011-2015).
In which segments did the impairments occur? Conventional generation segments were hit hardest at both EON and RWE. Of EON's 2011-2015 impairments, 74% were in the conventional generation unit, 33% of which due to low power prices. The renewables segment was responsible for only 5%; other segments contributing were trading and gas exploration with about 4% and 9% (EON 2011-2015).
Of RWE's 2012-2015 impairments, 82% occurred in the conventional generation segment, 59% of which were due to low power prices and shut-downs in Germany and the Netherlands. The renewables segment was responsible for around 9% of impairments, mainly due to regulatory changes in the Netherlands, Spain and Poland and due to delays in network connections and increased investment costs at German offshore wind parks. About 5% was in the German supply and distribution

networks segment (RWE 2011-2015).



(a) Net income and total impairments. **(b)** Impairments over book asset value.

Figure 3.8.5: Net income, total impairments and impairments over book asset value. Source: Own calculation based on Thomson Reuters Datastream.

For both utilities, impairments of conventional generation due to low power prices probably affected to a large degree gas-fired and hard-coal-fired power plants, as these have the highest marginal costs.

Nuclear capacity was also affected due to the government-required shut-downs in 2011, 2015 and 2017. Right after the accident in Fukushima, the German government first put the seven oldest reactors and the disputed power plant Krümmel on a moratorium and then permanently mothballed them. Two of those were owned by EON, two partly by EON and two by RWE. Two were shut down in 2015 (EON) and 2017 (RWE and EON).[9] While these shut-downs must figure among the impairments, they apparently played a minor role: record impairments were not in 2011, when by far the most nuclear power plants were retired, but later.

Analysing pre-divestiture impairments showed that high losses occurred mainly in fossil generation and to a limited extent in nuclear. This is in line with the risk contamination hypothesis, as both segments were shielded off from the growth (renewables) and stable (grid infrastructure) parts of the firms through the divestitures.

3.8.4.2 Valuation effects

If EON and RWE divested to attenuate risk contamination, they would have needed to shield off the risky assets, which were in danger of pulling the rest of the firm into default. One could thus assume that the pre-divestiture integrated firm had been undervalued. With the divestiture, the low-risk assets' market valuation increased due to the limited liability effect, while the high-risk

[9]The remaining seven power plants will be shut down by 2022.

assets' valuation decreased due to the loss of co-insurance from the low-risk business. Overall, the whole firm's valuation improved, if the limited liability effect dominates the loss of the co-insurance effect. Taken together this would be evidence for the risk contamination hypothesis.

A first step is to look at the annual market to book asset value of European utilities (figure 3.8.6). RWE and especially EON had relatively low values in the early 2000s, average valuations from around 2007, which then again deteriorated from around 2013/14. The 2015 valuations were below average though still in the range of both control groups.

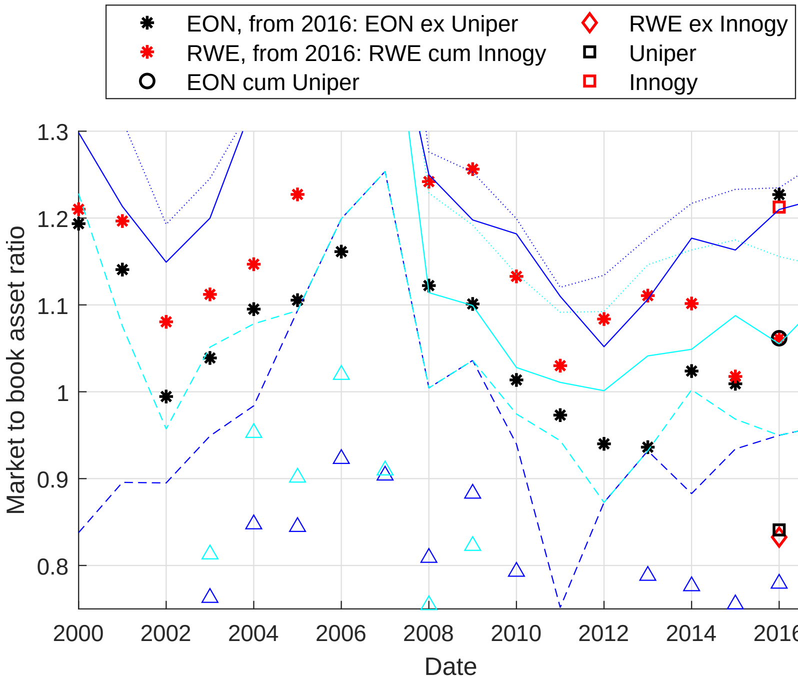


Figure 3.8.6: Market to book asset ratio, calculated by (market price year end · common shares outstanding + book value of total liabilities)/book value of total assets. Source: Own calculation based on Thomson Reuters Datastream.

To analyse the valuation effect of the divestitures, we can compare EON cum Uniper and RWE cum Innogy 2015 values (denoted by circles 3.8.6) with 2016 and 2017 (black star for EON, red circle for RWE).[10] EON cum Uniper's valuation improved from 1.01 to 1.06/1.13 (2015 black star compared to 2016/2017 black circles), as did RWE cum Innogy's, from 1.02 to 1.06/1.06 (2015 red star compared to 2016/2017 red circles). The best valued firms are Innogy (1.21/1.20) and the new EON (1.23/1.28), whereas Uniper (0.84/0.94) and RWE ex Innogy (0.83/0.77) have low market to book values, clearly below the minimums of their control groups in 2016/17.[11] This is first evidence for the risk contamination hypothesis.

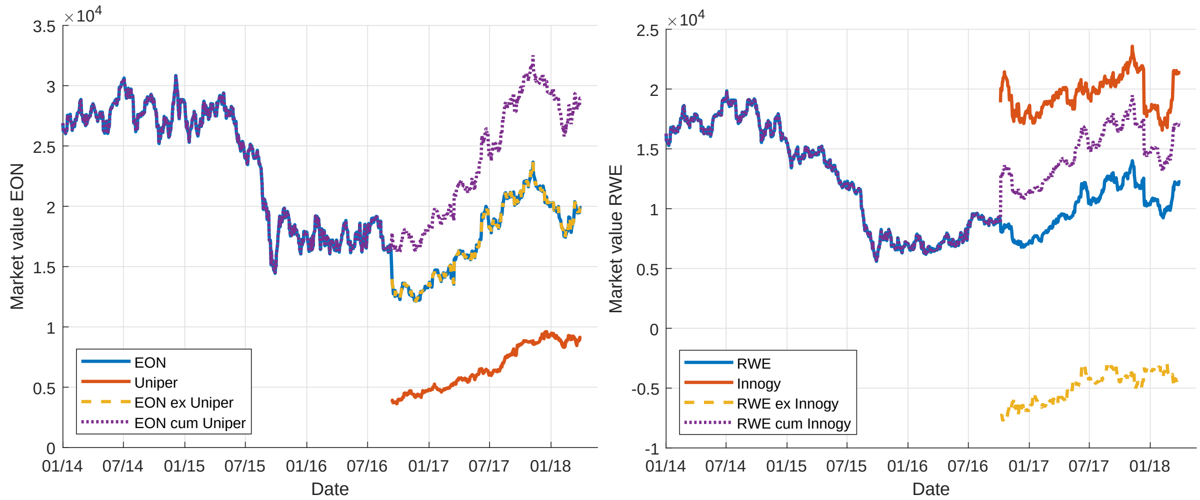
Comparing pre- and post divestiture valuation of the listed companies reveals that EON's valuation

[10] Calculation of the ex and cum values is described in the appendix. EON cum Uniper is a benevolent estimate, as it includes Uniper's full market value. It assumes that shareholders anticipated the complete sale of EON's Uniper stake, as announced in December 2014, even though EON still held a minority stake of 46.65% until June 2018, when it sold to Fortum.

[11] In 2017, Innogy deteriorates compared to Uniper, which is likely related to low profits in their UK segment (Innogy 2017), whereas Uniper values up, due to recovering electricity prices, pulling EON cum Uniper with it (Uniper 2017).

benefited more (1.23 and 1.28 in 2016/17 compared to 1.01 in 2015) than RWE's (1.02 to 1.06). This illustrates that EON's split, being the first of the two divestitures, was strategically more intuitive for the existing management: they got to be managers of a new firm with an improved valuation. RWE's CEO Peter Terium, on the other hand, had to make himself CEO of the subsidiary Innogy in order to be still heading a firm with high growth potential.

Figure 3.8.7 plots the daily development of market capitalisation at the two utilities. Two effects are striking. First, RWE ex Innogy's implicit negative valuation: on the day of Innogy's IPO on October 7, 2016, its market cap was at EUR -7.3 billion and at the beginning of 2018 still between -3 and -4 billion. Second, the jump in market value of RWE cum Innogy of about 45%, while EON cum Uniper only valued up by less than 9%.



(a) EON, Uniper and combined market value

(b) RWE, Innogy and combined market value

Figure 3.8.7: Market value calculated by market price · number of common shares outstanding. Source: Own calculation based on Thomson Reuters Datastream.

This is also illustrated in graph 3.8.8 showing market capitalisation prior to and on the days of Uniper and Innogy going public. The full calculation is described in appendix 3.13.6. The legend entries in brackets rest on the arbitrary assumption that Uniper's value halved and Innogy's value doubled by going public. This assumption would be in line with the risk contamination argument: the Uniper segment was co-insured by the rest of EON; it risk-contaminated EON. By going public, it lost the insurance. Innogy was co-insuring the rest of RWE; it was risk-contaminated by the conventional business. By going public, it lost the risk contamination. The graph shows that such an assumption would be consistent with the observed valuations.

The difference between Uniper's positive and RWE ex Innogy's implicit negative valuation might be surprising at first glance, since the two have very similar business models. However, first, RWE ex Innogy's valuation is only hypothetical and the result of Innogy's very high valuation. Uniper, in contrast to RWE ex Innogy, being a real traded firm, must have a positive valuation.

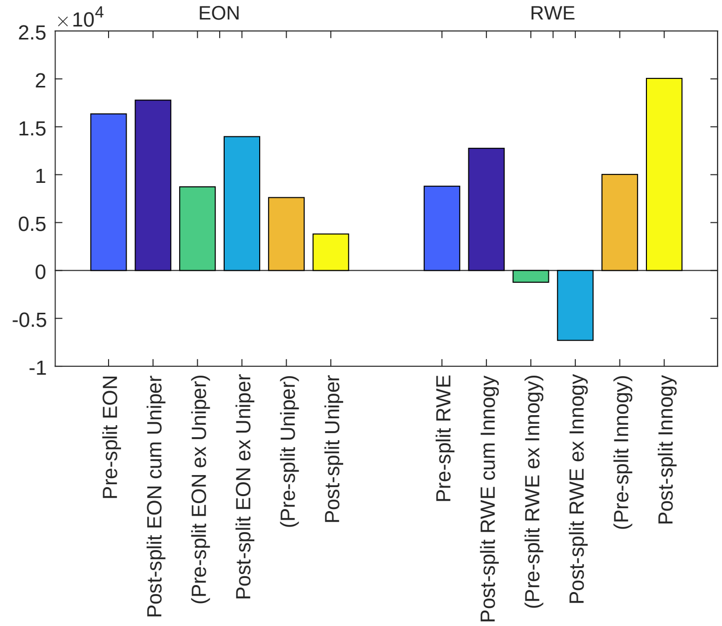


Figure 3.8.8: Market values on day -1 and 0 of Uniper's and Innogy's listing. Source: Own calculation based on Thomson Reuters Datastream.

A second explanation is that at the time of the splits, Uniper was indeed more attractive than RWE ex Innogy.[12] Why might Uniper be more attractive? The most obvious difference: Uniper did not operate any nuclear power plants. EON kept the nuclear segment and in turn EON cum Uniper might have benefited less from the risk separation effect than RWE cum Innogy.

3.8.4.3 Event study on reasons for risk contamination

This section investigates the reasons for a possible risk contamination using a share price event study. Events from January 2013 until November 2016 were collected.[13] Google news, the search functions of eight major German papers (Der Spiegel, Frankfurter Allgemeine Zeitung, Handelsblatt, Manager Magazin, Tagesspiegel, Sueddeutsche, Welt, Zeit) and the international edition of the Financial Times were used to identify events. Initial keywords were "EON" and "RWE", and events were tracked with varying keywords thereafter.

Overall, 26 events were identified that could possibly have had an impact on EON's and RWE's default risk. Four events had to be discarded because they coincided with earnings report publications, dividend payments or news about disposals. The two divestiture announcements and the two divestitures themselves - the so-called ex dates - were also added to the events, giving a total of 26 events tested.

A negative share price reaction to an event does not prove an increase in default risk and risk con-

[12] J.P. Morgan's valuation of enterprise value over EBITDA supports this: Uniper 2016/2017 estimates are higher than the implied values for RWE ex Innogy and also than EON's German nuclear unit (see appendix 3.13.7).

[13] January 2013 is about two years prior to the EON-Uniper spinoff announcement. EON stated that the strategy had been developed over one year. RWE had publicly rejected the possibility of a split until mid-2015. The last event included is Innogy's IPO.

tamination, but points more generally at investors seeing growth potential lost. To corroborate the risk contamination argument, it therefore is interesting to also look at events that led to a reduction in risk. If they cause positive share price reactions - regardless of or in contrast to their likely effect on future returns - this might support the risk contamination argument. It means that utilities' had been exposed to a risk involving high possible costs and a decision eliminating uncertainty relieved the share price of some of this downside risk priced in earlier.
The events can be classified into three categories:[14]

1. **Four events related to the divestitures**: the two utilities' announcements to split (November 30, 2014 and December 1, 2015) and the two divestitures (September 12 and October 7, 2016). All hypotheses - not only risk contamination - would predict a positive effect of the announcements on the parents' share price. Assuming risk contamination, one would also expect the parent to devalue on the divestiture day if it contains the 'contaminated' assets and to value up otherwise.

2. **Four events related to renewable energy policy reforms**. In January 2013, the German ministry for the environment launched efforts to reduce the power price for consumers by enforcing limits to renewable energy construction (Handelsblatt 2013-01-28). In June 2014, the Bundestag decided on a renewable energy law reform, among other things limiting feed-in tariffs for renewable energy (BMWi 2014-06-27).

   The risk contamination hypothesis predicts that changes in favour of renewable energies would increase utilities' risk due to their fossil- and nuclear-heavy portfolio and therefore have a negative impact on their share price. Events reducing uncertainty might also have a positive effect on share prices.

3. **Five events related to climate policy**. In November 2014, Energy and Economics Minister Sigmar Gabriel presented first ideas for a CO_2 levy on coal power plants in order to reach Germany's internationally agreed 2020 climate targets (Handelsblatt 2014-11-24). The negotiations with utilities and unions turned out to be difficult and finally also the heads of lignite-rich states allied against Gabriel. In June 2015, the levy was replaced with an about EUR 800 million annual premium in order to retire about 2.7 Gigawatt of lignite capacity between 2017 and 2020 (Tagesschau 2015-06-24, Frankfurter Neue Presse 2015-06-27).

   Events making the introduction of a CO_2 levy likelier are expected to have a negative impact on utilities' share prices, especially on RWE, which has a higher share of lignite. Events reducing uncertainty might also have a positive effect on share prices.

[14]Changes in commodity prices like electricity have a high impact on utilities, however, no news related to this could be identified. The previous section 3.8.4.1 therefore serves to cover the impact of depressed power prices on EON and RWE.

4. **Eleven events related to nuclear energy policy changes and news**. Due to the planned complete exit from nuclear energy by 2022, the question arose of whether utilities would be able to cover all costs for dismantling power plants and storage of nuclear waste. EON and RWE had EUR 16.6 and 10.4 billion in provisions for nuclear dismantling and storage as liabilities on their balance sheets. Together with the other three operators of nuclear power plants in Germany (Vattenfall, EnBW, and a small share by the Munich municipal utility), provisions added up to EUR 38.3 billion (Warth and Klein 2015).

   Policy makers had three main concerns. First, since on the asset side the use of the nuclear provisions was not ring-fenced, they could fall victim to impairments or bankruptcy. Against the backdrop of utilities' already shrunk balance sheets and market valuations, this suddenly seemed possible (Irrek and Vorfeld 2015).

   Second, even if the provisions were available, it was unclear how much of the cost they would cover. World-wide no experience exists with dismantling and storing nuclear equipment indefinitely into the future. In a study on different nuclear financing options, it was estimated that even infrastructure projects with long track records regularly have cost over-runs of 35-1,500% (Küchler et al 2014).

   Another factor adding to the uncertainty in estimates were discount rates. Because the bulk of the costs would arise far in the future, the real discount rate - interest earned minus inflation - had a high impact. While utilities used a discount rate of 4.58%, a report commissioned by the Ministry for Economics and Energy tested different scenarios ranging from 2.03 to 4.53% and obtained estimates between EUR 32.4 and 77.4 billion, i.e. up to two times or almost EUR 40 billion higher than the utilities' provisions (Warth and Klein 2015).[15]

   For these reasons cost estimates covered a wide range. The graph below gives an overview of estimates by various sources.

   Third, and in addition to these economic issues, utilities and government disagreed about the legal aspects regarding the division of costs between industry and state. The four major utilities published a joint report emphasizing the role of the state in ensuring legal security and argued that cost increases due to changes in regulations should entirely be covered by the state (Freshfields Bruckhaus Deringer 2015). The Ministry for Economics and Energy, on the other hand, stated that all costs are borne entirely by utilities (BMWi 2014).

   When EON announced the Uniper spin-off in late 2014, Minister Gabriel threatened to pass "lex EON", or the "parents are liable for their children law". The law - indeed passed later in October (DW 2015-10-14) - would make companies eternally liable for their nuclear op-

[15] Very low interest rates in recent years imply that these estimates at least partly under-estimated the real costs.

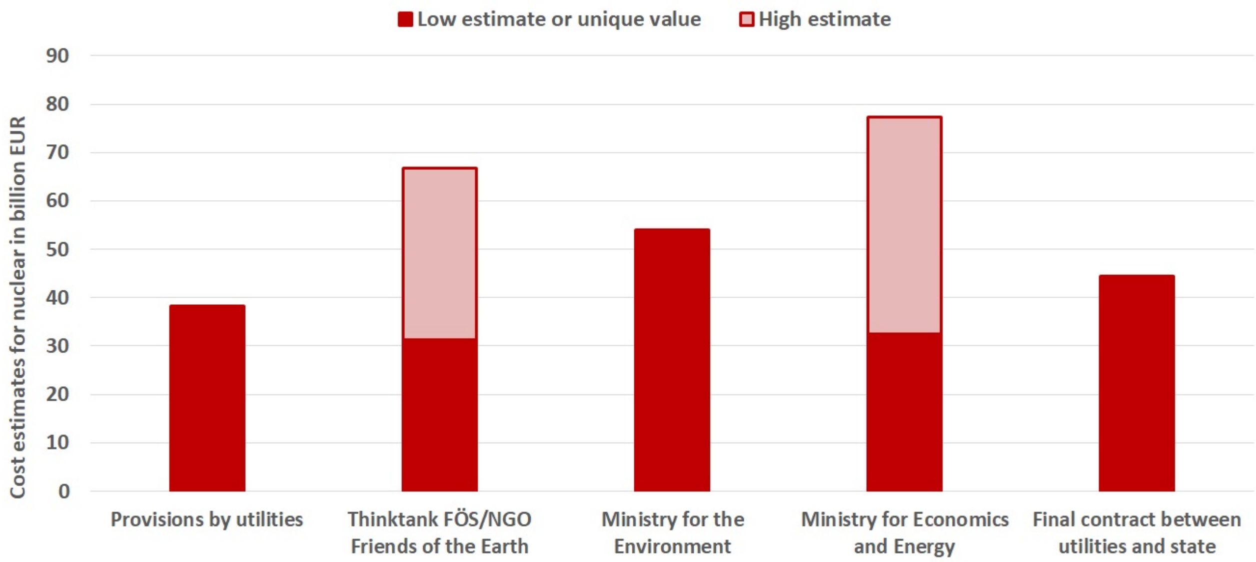


Figure 3.8.9: Cost estimates for nuclear dismantling and storage to be covered by five German utilities in EUR billion, all 2014 prices. Sources: Own illustration based on references.

erations and waste, in contrary to existing regulations according to which companies were only liable for five more years following a legal separation.[16] EON would thus have remained liable for a segment that was supposed to be operated by Uniper. In September 2015, EON's supervisory board agreed to change their initial plans and keep the nuclear segment with EON (Handelsblatt 2015-08-13).

During the coalition talks in November 2013, the Social Democratic Party (SPD) had first brought up the idea of a state-run fund to secure nuclear provisions as had been set up in France and Switzerland. The utilities initially opposed the idea of an external fund. From their point of view, using nuclear provisions as a debt-like item for investments was more attractive than the option of cashing them out.

When political pressure increased, however, and numbers discussed were higher than existing provisions, a fund seemed appealing. Utilities offered to immediately pay their existing provisions into a fund in exchange for the state taking all responsibility for operating existing nuclear plants as well as ensuring dismantling and storage. The government initially demanded that the existing provisions be secured in a fund, but utilities remain responsible for the operation of the plants as well as for any cost increases of dismantling and storing (Welt 2013-11-14, Spiegel 2014-05-11).

Between 2014 and 2016 a number of reports were published, two of which, commissioned by the Ministry for Economics and Energy (BMWi), turned out to be the most influential: the

[16] Indeed the Swedish parent Vattenfall in 2012 had cut links with its German subsidiary, supposedly in order to no longer be liable for German nuclear power (Casali and Hawkins 2016).

legal opinion by Becker Büttner Held (2015) that nuclear provisions were not sufficiently safe unless transferred to an external fund, and the report by Warth and Klein (2015) with cost estimates ranging from 6 billion less to 40 billion more than utilities had provisioned.

In November 2015, the government set up an expert commission tasked with reviewing the financing for the phase-out of nuclear energy. The final "law on the reorganization of responsibility in nuclear waste management" reflected the recommendation by this commission, which in turn reflected the two BMWi reports. It was a compromise: for storage, utilities paid 24 billion - 7 billion more than provisioned - into a state-run fund (10.3 billion by EON and 6.8 billion by RWE) in exchange for ridding themselves of any storage responsibilities and of any liabilities for future cost increases. Dismantling of nuclear power plants remained the utilities' responsibility and on their balance sheets.

In the event study, negative share price reactions are expected for events that made utilities' cashing out of nuclear provisions or their unlimited liability in case of cost increases likely. Events reducing uncertainty might also have a positive effect on share prices.

Figure 3.8.10 plots EON's and RWE's share price with lines representing events in the different colours. It shows a widening gap between the utilities and the Stoxx Europe 600 index compared to their January 1, 2012 prices. Renewable energy related events are spread throughout 2013 and 2014; climate policy related events occur mainly in 2015. Nuclear related events started in late 2013 and intensified in the second half of 2015, coinciding with share prices plummeting.
Table 3.13.8.1 in the appendix (3.13.8.1) lists all events with their expected impact and the regression results. The estimation method is also described in the appendix, as well as the results of a Brown Warner test with randomized event dates. Results were also tested and found mainly robust for event and estimation windows of one to eleven days and 20 to 200 days respectively. The specification chosen was one day for the event period and 100 days for the normal period. The short event period is justified to distinguish between events that follow each other closely like the ones in late 2016.
The results of the event study are as follows:

1. **Positive significant effect of divestiture announcements**. As predicted by all hypotheses (not only risk contamination), there is a significantly positive share price reaction on the Uniper spin-off announcement day for EON of 4.1% abnormal returns compared to the Stoxx 600 Europe Index and of 16.5% on the Innogy carve-out announcement day for RWE. This indicates that shareholders expected positive value creation from the divestitures and is in line with all hypotheses discussed.

   Regarding the ex-date effects, both EON's and RWE's reaction to the Uniper spin-off was

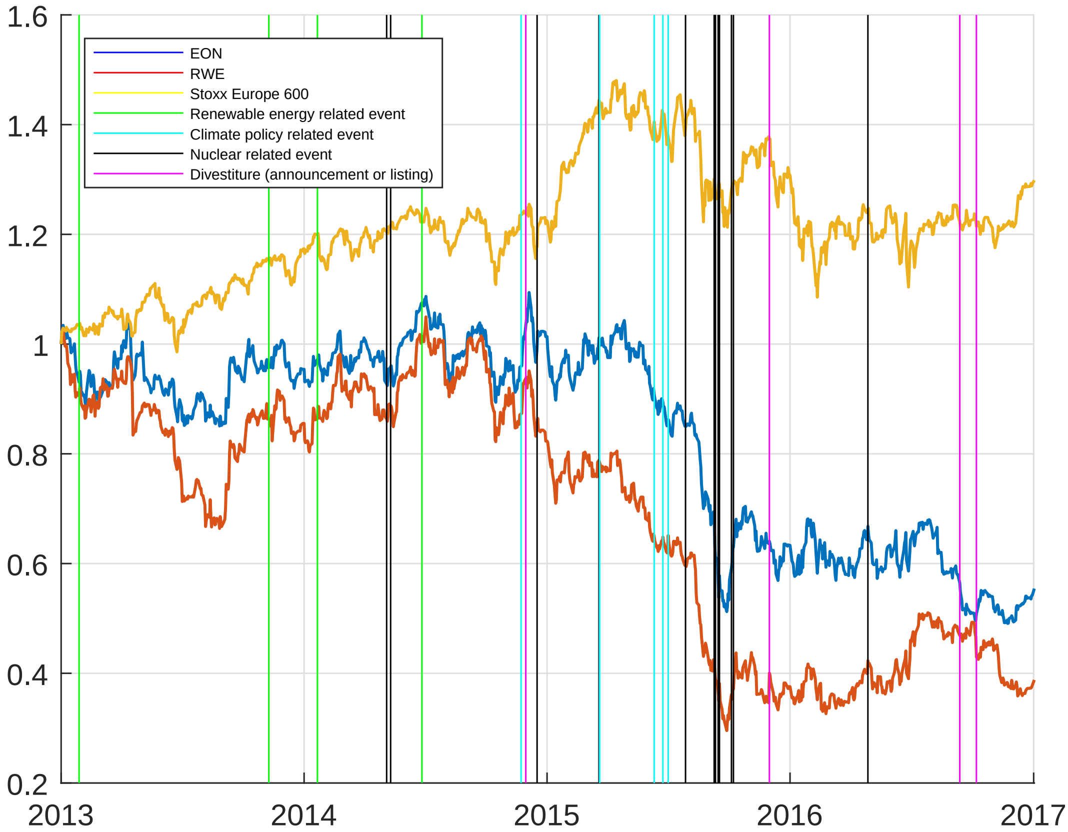


Figure 3.8.10: EON and RWE price of common stock and Stoxx Europe 600 normalized by their January 1, 2013 value, and event types in different colors. Source: Own illustration based on Thomson Reuters Datastream.

negative but insignificant. They both reacted significantly, though, to the Innogy carve-out. EON's share price valued up by 3.7% compared to the index, whereas RWE devalued by 7.0%. The reason for these effects might be that only the RWE-Innogy split offered perfect risk separation. The split drove investors away from the now fossil and nuclear heavy RWE stock towards the clean Innogy and also to the relatively cleaner competitor EON (which still held the nuclear segment).

2. **No impact of renewable energy related reforms**. The two utilities' stock prices did not react significantly to any of the renewable energy related events and often with reactions opposite to the predicted effects.

3. **Limited impact of climate policy in favour of RWE**. Regarding climate policy, the government's first efforts in late 2014 and early 2015 did not seem to weigh on EON's or RWE's share price. The final decision on June 24, 2015 not to implement any CO_2 levy and instead reward the retirement of lignite plants, however, gave a significant boost to RWE's share price: abnormal returns compared to the index were 2.5%; when the full compromise was published on July 2 the reaction was 5.8%. Given that RWE announced its divestiture almost half a year after this favourable decision, immediate fears of climate policy should not have played any

role.

EON's lack of a reaction makes sense: due to its lower relative share of lignite, it was less threatened by a levy.[17]

4. **High impact of nuclear-related events**. From May 2014 until August 2015, nuclear related events had no significant impact on share prices. This changed in September:

   (a) **Negative impact of EON keeping nuclear**. On September 9/10, 2015, investors strongly punished EON for the decision to keep its nuclear segment with significantly negative abnormal returns of 2.4% and 5.8%.

   (b) **Negative impact of higher cost estimates**. Four days later, Spiegel leaked the results of the "stress test", the Warth and Klein report commissioned by the Ministry: allegedly an up to 30 billion funding gap for overall nuclear provisions existed, as utilities were too generous in their discount rate estimates (Spiegel 2015-09-15, Wirtschaftswoche 2015-09-17). Abnormal returns compared to the Stoxx on that day were -6.6% (EON) and -3.5% (RWE).

   (c) **Positive impact of lobbying efforts**. EON's and RWE's share price suffered further losses until on September 17 the government intervened. Minister Gabriel declared that he did not to know about the EUR 30 billion funding gap, that the report was not yes finalized and that leaked results were "irresponsible speculations" (Spiegel 2015-09-19). The share prices started recovering with significant positive abnormal returns of 8.2% (EON) and 1.0% (RWE).

   (d) **Positive impact of resolution of nuclear risk**. When the Warth and Klein study was published on October 8, one could still read about a possible funding gap in the worst case of even EUR 40 billion. Share prices did not react to it, though, and media painted the results in a positive light. For example, a Reuters article at the time was titled, "Germany says firms set aside enough nuclear decommissioning funds" (Reuters 2015-10-10). Policy makers had successfully signalled that the utilities were too big to fail. And indeed, when the nuclear commission published their recommendation on the division of costs and liabilities on April 27, 2016, while EON and RWE complained that it "placed too much of a strain [...] on their economic capacity" (FT 2016-04-27), their share prices showed significant positive abnormal returns of 3.0% and 5.3%. This corroborates the argument of risk contamination by the nuclear segment. Even though the amounts to be paid into the fund by EON and RWE (10.3 and 6.8 billion) were each more than one

[17] For both utilities, of course, climate policy in general was of high relevance. In 2014, however, European CO_2 prices were on a record low. Only from late 2017 did the EU Commission take concrete steps to reduce emissions trading certificate amounts.

billion or 13% and 22% above their existing provisions for nuclear storage, they were moderate enough that the market remunerated the liability cap on storage cost (EON, RWE 2015, 2016).

The event study established strong evidence for risk contamination from the nuclear segment. Supporting evidence is the high amount of uncovered nuclear costs discussed, the market's negative reaction to the nuclear segment staying with EON and to the alleged funding gap, EON cum Uniper's absence of a valuation increase on the ex date, the policy makers' hesitation between a polluter-pays-all and a too-big-to-fail attitude and the market's relief at the costly but risk-reducing nuclear commission proposal.

3.8.4.4 Interview results

Fifteen out of 20 interviewees thought that the utilities' decision to split was driven by some sort of risk contamination.

Outsiders attributed a big role to the nuclear risks. As one equity analyst put it: "The utilities were confronted with two main problems: the flooding with renewable energies resulting in a drop in electricity prices and the issue of the nuclear exit. In 2014, they were going towards a valuation of zero - the whole companies were worth less than their grid segments. So either the market's valuation was totally wrong or there were big risks due to insufficient nuclear provisions. To be honest, the former was exactly the situation before the nuclear commission resolved the problem in favour of the utilities." (Interview 3)

Among the utility insiders, some staff members were equally outspoken: "The spin-off announcement was a shock for the whole staff at EON. We quickly understood that it was about nuclear energy. They wanted to create a bad bank for the liabilities. That was quickly blocked with the 'parents are liable for their children' law. Otherwise, if it had been too expensive, you could have let go of Uniper and after five years you're off." (Interview 10) "RWE was worried that the nuclear liabilities would drag down the whole shop. Then there was EON's failed and naive move. So we learned." (Interview 7)

The interviewed managers were much more cautious. Also publicly, EON never spoke about any risk-related drivers, let alone nuclear liabilities (EON 2014-11-30). RWE, in contrast, even emphasised their continued responsibility for nuclear liabilities. During the investor phone call on the divestiture announcement day, CEO Peter Terium argued that RWE would increase "visibility of the downstream and renewables business that have been overshadowed by the conventional business" and benefit from increased financial flexibility, as it could sell further Innogy shares if liquidity was needed, while assuming "full responsibility for nuclear liabilities" (RWE 2015-12-01).

Interviewees judged RWE's the more successful strategy, but only because EON's move was altered by policy makers: "EON wanted to bring nuclear into the spin-off deal - that would have been a successful move. But RWE's strategy was much better in the end: the good part was not burdened by nuclear. And from the point of view of policy makers, RWE's liability mass did not decrease. If liquidity was needed, they could always sell Innogy for cash." (Interview 3) RWE killed two birds with one stone: separating the risks and as a result being able to raise money for the nuclear cash-out. But it came with the price of a business model that was unsustainable in the long-run and therefore only a temporary solution: "RWE could not survive without Innogy. So they said: why not swap with EON?" (Interview 19) With the asset swap announced in 2018, RWE will obtain both EON's and Innogy's renewables assets in exchange for the grid- and customer-related part of its own Innogy share.

In summary, there is strong support for risk contamination based on the firms' and subsidiaries' valuations pre- and post-divestiture, a share price event study and interviews. Likely sources of risk contamination were further losses by fossil fuel-fired power plants and the acute risk of unmanageably high nuclear dismantling and especially storage costs linked to the nuclear exit.

3.9 Drivers related to investor preferences

3.9.1 Trading and share price returns on the ex date

First evidence in line with investor preferences driving the splits would be if investors rebalanced their portfolios on the divestiture day and if that had a significant impact on share price returns.

To see whether there is increased trading on the ex date, the change in trading volume as compared to an index and a normal period of 100 days is calculated. The detailed model is laid out in the appendix (3.13.8.2). It reveals significant abnormal trading of 374% for EON and 521% for RWE. Trading increased in a comparable manner when the competitor's subsidiary went public, i.e. at EON on the Innogy ex date and at RWE on the Uniper ex date.[18]

Only the Innogy ex date triggered significantly positive abnormal returns for EON (4%) and negative ones for RWE (-7%). So there is evidence that both EON and RWE investors rebalanced their portfolios on both the Uniper and Innogy ex dates. Rebalancing on the Innogy ex date seemed to have been in favour of Innogy and EON and to the detriment of RWE.

This is in accordance with a financial driver such as risk contamination, though, as investor preferences would predict only positive abnormal returns on the ex date. If investors wanted to hold

[18] Apart from that, only few events triggered a significant increase in trading, in accordance with the most significant impact on returns described earlier: the decision against a CO_2 levy for RWE, the divestiture announcements for EON and RWE respectively, EON's decision to keep the nuclear segment, the leak of the Warth and Klein results for both. Appendix 3.13.8.2 contains methodology and detailed results.

only the uncontaminated part because of risk contamination, not because of their individual preferences, they might wait and trade only on the ex date to avoid transaction costs. This could also explain why there is no significant returns effect on the EON-Uniper ex date: risk separation was not perfect since nuclear stayed with EON.

3.9.2 Sin stocks, search for yield or falling profits?

Another hint at investor preferences driving the splits would be if investors had expressed support for the splits or interest in certain firm segments.

In December 2016 the number of investors committed to selling off fossil fuel assets had jumped to USD 5.2 trillion in assets under management doubling in just over a year (Carrington 2016). One example is the Norwegian USD 900 billion sovereign wealth fund, the world's biggest after Japan's. In November 2014, the fund, which held 2.1% of EON's stock and 2.2% of RWE's stock, considered a divestment from firms engaged in mining or burning of coal. In May 2015, the fund sent a letter to RWE asking about their plans to exit coal and whether they would consider a split à la EON. In June, Norway's parliament formally endorsed the move to sell off coal investments (Manager Magazin 2014-11-26, 2015-05-06). In 2017, the fund still held at least 2.3% of EON and 1.4% of RWE stocks (Norges Bank 2018). What had happened?

As with many investors that committed to divestment policies, the policies left room for exceptions. In the case of the Norwegian fund, their guidelines only recommended to divest from companies with more than 30% revenues from coal. RWE does not reach that threshold.[19] Even if a company does but is the process of decreasing its coal activities, the fund does not need to divest (Wolff 2018).[20] Probably other investors apply similar guidelines. Whereas at least 16 of EON's and 14 of RWE's investors committed to some sort of fossil fuel divestment since 2013, only one of these actually divested from EON and two from RWE. The overall share of stocks held by these investors actually increased since 2013, as figure 3.9.1 shows.

This does not mean that utilities were not under pressure from investors. In September 2016, the city of Bochum, which held about 1.1% of RWE's stock decided to divest completely. Essen, Düsseldorf, and Dortmund, which were part of the municipal shareholders making up around 23% of RWE holdings, also temporarily considered divesting. This was, however, after RWE's planned split was already long public, so unlikely a driver. And financial reasons played the predominant role: cities were hit hard by falling dividends, which in 2016 were zero at RWE for the first time (Grüne 2016-04-29, Handelsblatt 2017-08, WAZ 2016-09-15).

Many global investors that committed to divest from fossil fuels also mixed ethical and financial

[19] Even if excluding revenues from Innogy, lignite and nuclear revenues were responsible for less than 23% of revenue in 2016 and 2017 (RWE 2016, 2017).

[20] This policy was changed in April 2019 resulting in the divestiture from RWE.

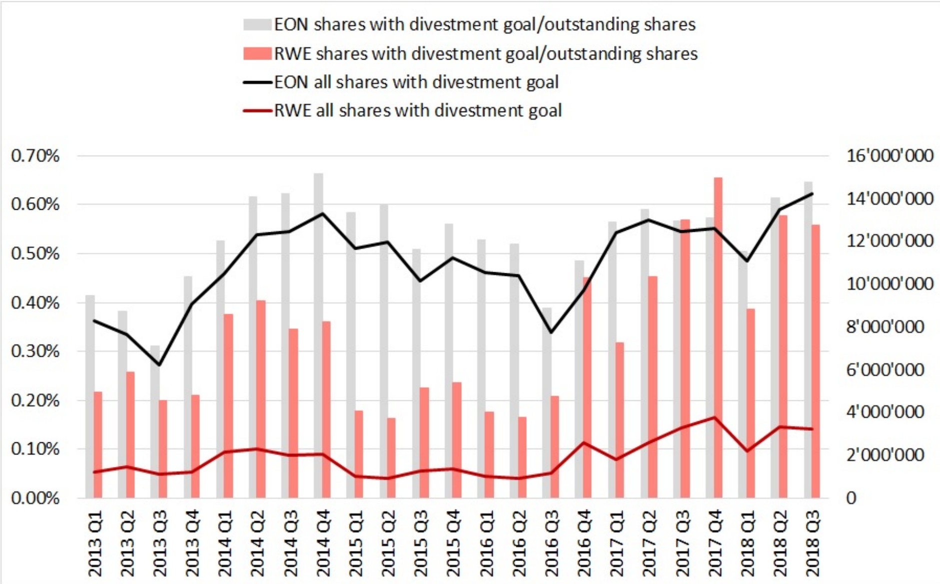


Figure 3.9.1: Percentages and total shares held by investors committed to divesting from fossil fuels. Source: Own calculation based on Thomson Reuters Datastream, Bloomberg and Gofossilfree.org (2018)

arguments. For example, the parliamentary committee recommending Norway's exit from coal assets stated that "investing in coal companies poses both a climate risk and a future economic risk" (Reuters 2015-05-28). This economic risk argument is more akin to the risk contamination hypothesis: if conventional energy becomes unprofitable and excessively risky, a split can offer investors the opportunity to invest in a profitable, uncontaminated business. This argument is distinct, though, from investors' heterogeneous demand for different risk-return profiles or their exclusion of stocks on ethical grounds.

3.9.3 Interview results

Thirteen out of 20 interviewees thought that investors' preferences played a role. A financial journalist thought that "pension funds and other institutionals had high pressure to invest. And grid infrastructure is a pearl in a low interest rate environment." Interviewees also acknowledged, though, that in the energy case it is hard to distinguish a preference for low-risk assets, ethical preferences and the fear of further losses due to risk contamination. "We wanted to get rid of everything with commodity price risk", said one EON staff. "A lot of investors did not want any risk, like municipalities. Mainly because they thought that our past investments had failed." (Interview 6). An equity analyst thought that "there is a lot of interest now in ESG investments, like products with lower CO_2 emissions. Why? I think it is a mixture of risk preferences, return expectations and ethical considerations." (Interview 9)

So while more and more investors wanted to exit fossil fuels and demand for low-risk renewable energy and grid infrastructure assets was apparently high, this could not be traced to one specific reason. It is in line with search for yield, ethical considerations as well as the avoidance of economic loss. Further, since holdings from divestment committed funds did not seem to decrease, it is unclear whether the divestment movement was a concrete factor in the utilities' decisions to split.

3.10 Conclusion

This study investigated why the two biggest German utilities, EON and RWE, split up in 2016. Four possible types of drivers for divestitures were identified from the divestiture literature: operations and management, investing, financing and investor preferences. These drivers were tested in the empirical case of the EON and RWE divestitures of 2016. The results of different methods - comparative descriptive statistics, interviews, gray literature and event studies - converged in rejecting drivers related to operations, management and investing. Drivers related to investor preferences could not sufficiently be distinguished from risk contamination.

The analysis supports debt overhang as one driver, as EON and RWE accumulated higher liabilities than their peers due to provisions for nuclear dismantling and storage. There is also strong evidence for risk contamination. This is tested by analysing EON's and RWE's previous losses and the valuations pre- and post-divestiture and by conducting share price event studies and interviews. Likely sources of risk contamination were further possible losses by fossil fuel-fired power plants and the acute risk of unmanageably high nuclear dismantling and especially storage costs linked to the nuclear exit.

In 2015 alone, the year when discussions about provisions for decommissioning nuclear power plants and storing toxic waste intensified, EON's market cap decreased by half and RWE's by 75%. Investors doubted the adequacy of utilities provisions for nuclear related costs, and feared major cost increases while utilities being unlimitedly liable. Even though utilities' nuclear provisions had increased considerably, in 2015 a study estimated a funding gap of up to EUR 40 billion for Germany's nuclear capacity overall.

Utilities restructured to avoid further risk contamination of their healthy assets (renewables and grid infrastructure) by the conventional power generation business (fossil fuel and nuclear plants). There was one major difference between the two utilities' strategies: EON announced to spin off its risky conventional power generation and its trading segment to the new subsidiary Uniper. For RWE, being the second mover, it was already clear that policy makers would not allow nuclear liabilities being spun off. As a result, RWE carved out renewables and grid infrastructure into the new Innogy, turning itself into a conventional generation and trading utility only financially invested in the growth firm Innogy.

3.11 Policy implications and outlook

The example of German policy making shows that an ambitious energy transition - an increase in renewables and the simultaneous exit from nuclear - can come at a cost to incumbent utilities. One could argue that severe losses or bankruptcies of main electric utilities are necessary evils in the transition away from a fossil fuel- and nuclear-based power market. However, under certain circumstances there are problems with this approach:

1. In Germany, the utilities' nuclear provisions were not ring-fenced. If utilities had faced further impairments or bankruptcy, tax payers might have had to burdened all costs for dismantling plants and storing nuclear waste estimated at between EUR 32 and 77 billion (Warth and Klein 2015).

2. Many authors argue that in the absence of affordable storage solutions, fossil fuel-based power plants are still needed to balance out fluctuating renewable energy in the mid-term. In Germany, about 60% of this capacity was operated by the big incumbent utilities - EON, RWE, Vattenfall and EnBW (BMWi 2018; Bundesnetzagentur 2019). A default of one of these big four might have thus affected security of supply in power generation.

3. In addition to power generation, the big German utilities also played a main role in electricity trading, operation of distribution grids and provision of customer services. A bankruptcy might have thus endangered not only security of supply in power generation but in the whole energy value chain.

In this market environment, risking utilities' bankruptcy might have destroyed more value than it created. For this reason policy makers were caught in between a 'polluter pays' and a 'too big to fail' attitude, leading to indecisive, contradictory and possibly too lenient policies. Three measures might have altered the market environment ex-ante such as to avoid the problems described above:

1. The government should have set-up a well-endowed, ring-fenced and state-run fund for nuclear provisions much earlier, following the example of countries like France and Switzerland. German utilities had their golden times in the late 2000s. This would have been the time to skim off some profits to secure appropriate funding for nuclear dismantling and storage.

2. Even though heavily debated and possibly not necessary in Germany at the time, a well-designed and transparent capacity market might have its merits depending on the existing power plant fleet and structure of the electricity market. As Weber (2017) notes, "prices based on volatile marginal costs and a long-term capital lock-up are not a good basis for substantial

investment. In most deregulated electricity markets in the US and Europe capacity mechanisms exist, which together with energy trading ensure the security of supply."

3. A less oligopolistic power market structure helps against the moral hazard of 'too big to fail'. Germany's oligopolistic market structure is partly the effect of natural monopoly tendencies and partly caused by the governmentally-encouraged mergers in the 1990s. While oligopolies especially in grid infrastructure cannot be avoided, moves towards further market concentration like the recent EON-RWE asset swap should be viewed critical. The benefits of scale stand against not only potential price increases for consumers but also the exposure of the power market to concentration risk and the need for bail-outs by tax payers.

Further research might look into how other sectors or sub-sectors can benefit from past experiences like the German case. An interesting case would be the coal exit, Germany's next big step in the energy transition. With the coal commission just having adopted its recommendations to exit hard coal- and lignite-based power by 2038, parallels and differences to the nuclear exit will be interesting to explore. Another interesting sector is mobility: applying these lessons to the transformation of the market for combustion engines could possibly save costs for tax payers and industry alike.

This paper has identified risk contamination as a possible major concern in the transition of the power sector towards renewables. Further research could quantify this potential systemic risk by devising methodologies and measures to conduct stress tests on the energy sector. This has already been done in finance research regarding the effect of interconnections among financial actors in the aftermath of the 2008 crisis (e.g. Tasca and Battiston 2016) and regarding the impact of climate risk on the financial system (e.g. Battiston et al 2017). A similar approach to the energy sector, with a stress test measuring the consequences of different transition scenarios on incumbent investors could be useful to derive low-cost policy recommendations.

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Interview 7: RWE staff, 2018-06-21.

Interview 8: EON staff, 2018-06-22.

Interview 9: Equity analyst, 2018-06-22.

Interview 10: EON staff, 2018-06-23.

Interview 11: Financial journalist, 2018-06-26.

Interview 12: Academic, 2018-06-28.

Interview 13: Financial journalist, 2018-06-28.

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3.13 Appendix

3.13.1 EON's and RWE's generation portfolios and geographical origin of revenues

See figure 3.13.1 and 3.13.2.

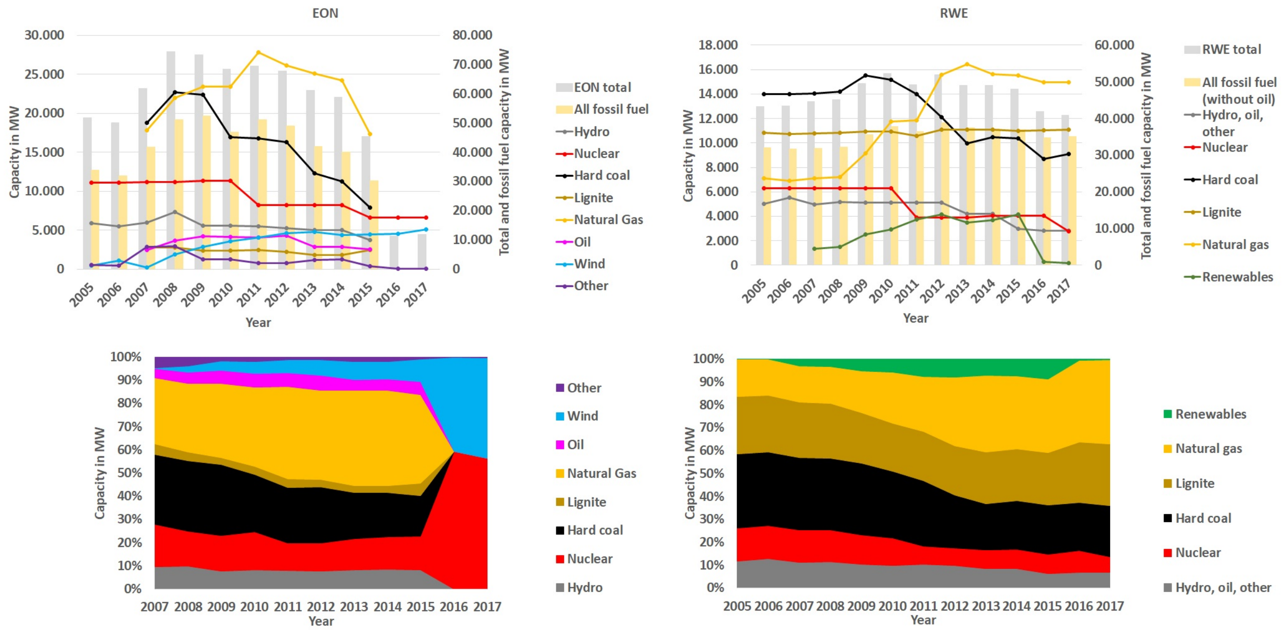


Figure 3.13.1: Generation portfolios at EON (left) and RWE (right). Source: Own calculation based on EON and RWE annual reports.

3.13.2 The Stoxx Europe 600 Utilities control groups

3.13.2.1 Method

The method for establishing the control groups is as follows:

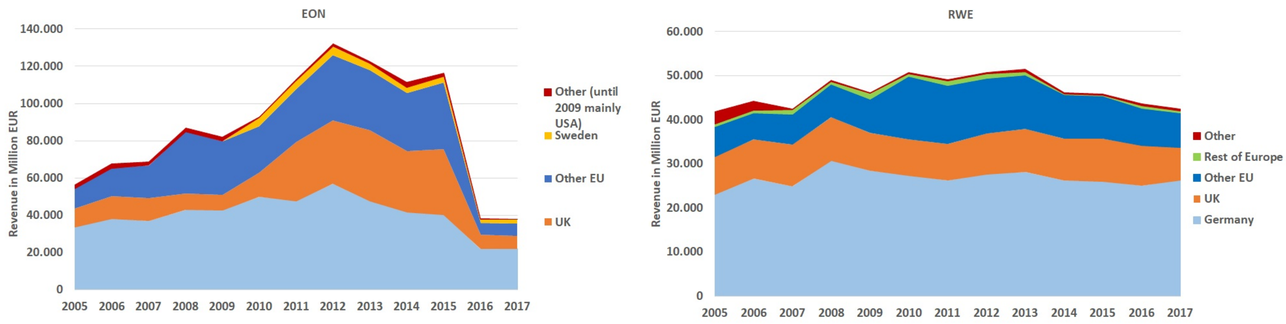


Figure 3.13.2: Origin of revenues by country at EON (left) and RWE (right). Source: Own calculation based on EON and RWE annual reports.

- **All Stoxx 600 Europe Utilities without EON, RWE, Uniper and Innogy**. The Stoxx 600 Europe index has a fixed number of 600 components representing large, mid and small capitalization companies among 17 European countries covering approximately 90% of the free-float market capitalization of the European stock market. The countries that make up the index are Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Ireland, Italy, Luxembourg, the Netherlands, Norway, Portugal, Spain, Switzerland, Sweden and the United Kingdom. The Stoxx 600 Europe Utilities index contains the utilities thereof. As of November 2018, it had 28 components, which are listed in table 3.3. Excluding EON, RWE, Uniper and Innogy, the control groups results in 24 firms.

- **Only merchant or diversified electric utilities without majority shareholder**. This sub control group is constructed in order to avoid any biases arising from utilities that are very different from EON and RWE in terms of business model, products or shareholders. The sub control group is received by creating three sub control groups and then taking the overlap of those.

  The first sub control group contains only Stoxx Europe utilities whose returns are not almost entirely governmentally regulated. The information is obtained from the utilities' annual reports from 2014 to 2017, the years that are most relevant for this research. Examples for entirely regulated utilities, thus not part of the sub group, are the Spanish gas grid operator Enagas or National Grid, Great Britain's electricity transmission network. The reason for excluding them is that utilities with regulated returns are less exposed to commodity and policy risk and might be able to take up more debt (Interview 12) also reflected in different credit rating methodologies (Moodys 2017). 5 out of the 24 non-German utilities were almost entirely regulated.

  The second sub group is created by excluding utilities not mainly active in electricity or gas, which are EON's and RWE's main products. Annual reports are used to identify 6 utilities out of 24, which are mainly active in the waste and water sectors. These markets are likely governed by different pressures than the ones our case study utilities operate in.

The third sub group excludes any utility that had an influential shareholder at some point between 2014 and 2017. Influential shareholders are defined as those holding veto power or own golden shares.[21] Data for this is taken from Thomson Reuters Datastream. EDF or Fortum are examples of utilities dominated by the French and Finnish state respectively. 6 utilities fell in that category. They might experience certain benefits or also pressures from their dominant shareholder, differentiating them from utilities with diversified shareholder bases (Maug 2002). The overlap of these three different sub groups creates a sub control group that consists of only 9 utilities.

3.13.2.2 List of Stoxx Europe 600 Utilities components used for control group

See table 3.3.

3.13.3 Capital expenditure indicators

3.13.3.1 Capital expenditure correlations

See table 3.4.

3.13.3.2 Capital expenditure over operating cash flows

See table 3.5.

3.13.4 EBIT(DA) and free cash flow of main segments

See figure 3.13.3.

3.13.5 Leverage and liquidity indicators

See figure 3.13.4.

[21] A golden share gives its owner the right to outvote all other shares in certain specified circumstances.

	Country	Mainly regulated business	Products not mainly electricity or gas related	Any majority shareholder 2014-2017
A2A SpA	Italy			
Centrica PLC	Great Britain			
EON	Germany			
EDF	France			X
EDP	Portugal			
Enagas	Spain	X		
Endesa	Spain			X
Enel	Italy			
Engie/GDF Suez	France			X
Fortum	Finland			X
Iberdrola	Spain			
Innogy	Germany			
Italgas/Snam	Italy	X		
National Grid	Great Britain	X		
Naturgy Energy Group	Spain			
Orsted/Dong	Denmark			X
Pennon Group	Great Britain		X	
Red Electrica Corporation	Spain	X		
Rubis	France		X	
RWE	Germany			
Scottish and Southern Energy	Great Britain			
Severn Trent	Great Britain		X	
Suez Environnement	France		X	
Terna	Italy	X		
Uniper	Germany			
United Utilities Group	Great Britain	X	X	
Veolia Environnement	France		X	

Table 3.3: List of Stoxx Europe 600 Utilities components. Source: https://www.stoxx.com/index-details?symbol=SX6p, accessed on November 10, 2018.

EON capex with total capex	Generation	67.98%
	Renewables	26.84%
	Germany networks and customer solutions	77.62%
EON capex with segment operating cash flows	Generation	98.75%
	Renewables	-38.52%
	Germany networks and customer solutions	23.61%
RWE capex with total capex	Germany power generation	-0.30%
	Conventional power generation	98.41%
	Renewables	15.15%
	Germany sales and distribution networks	60.21%
RWE capex with segment cash flows	Germany power generation	25.89%
	Conventional power generation	-22.06%
	Renewables	59.42%
	Germany sales and distribution networks	13.22%

Table 3.4: Correlations of segment capital expenditure data with total capital expenditure and with segment operating cash flows. Source: Own calculation based on EON and RWE annual reports. Years are as plotted in the graph above.

3.13.6 Calculation of market capitalisation of parents and subsidiaries pre- and post divestiture

0 always refers to the divestiture day, i.e. 12/09/2016 for the EON-Uniper spinoff and 07/10/2016 for the IPO of Innogy. -1 is the trading day prior to that.

$$\text{Post-split Uniper} = \text{Uniper}_0$$

$$\text{Pre-split EON} = \text{EON}_{-1}$$

$$\text{Post-split EON cum Uniper} = \text{EON}_0 + \text{Uniper}_0$$

$$\text{Pre-split EON ex Uniper} = \text{EON}_{-1} - \text{Uniper}_0$$

$$\text{Post-split EON ex Uniper} = \text{EON}_0$$

$$\text{Post-split Innogy} = \text{Innogy}_0$$

$$\text{Pre-split RWE} = \text{RWE}_{-1}$$

$$\text{Post-split RWE cum Innogy} = \text{RWE}_0 + (1 - 0.768) \cdot \text{Innogy}_0$$

$$\text{Pre-split RWE ex Innogy} = \text{RWE}_{-1} - \text{Innogy}_0$$

$$\text{Post-split RWE ex Innogy} = \text{RWE}_0 - 0.768 \cdot \text{Innogy}_0$$

		2010	2011	2012	2013	2014	2015	2016	2017	Average
EON capex over segment operating cash flows	E.ON SE Group	78.07%	83.01%	68.67%	99.56%	56.36%	59.30%	79.74%	-148.01%	74.16%
	Generation	66.17%	64.71%	56.88%	57.54%	48.73%	37.53%			55.26%
	Renewables	91.97%	80.96%	151.78%	67.90%	105.25%	87.67%			97.59%
	Germany networks and customer solutions	62.56%	54.43%	37.31%	30.27%	40.25%	84.21%	47.40%	28.07%	51.50%
RWE capex over segment cash flows	RWE Group	115.98%	115.30%	115.61%	78.09%	58.41%	86.79%	86.18%		84.72%
	Germany power generation	37.29%	41.82%	68.37%						
	Conventional power generation			131.47%	121.21%	47.61%	37.86%	24.78%		84.54%
	Renewables	479.69%	585.11%		178.70%	488.51%	774.07%			480.43%
	Germany sales and distribution networks	83.39%	121.94%	115.45%	53.73%	48.26%	65.66%			70.78%

Table 3.5: Capital expenditure in EON's and RWE's main segments over operating cash flows in the same segments. Average for EON 2010-2015, for RWE 2012-2015. Source: Own calculation based on EON and RWE annual reports.

3.13.7 Enterprise value over EBITDA

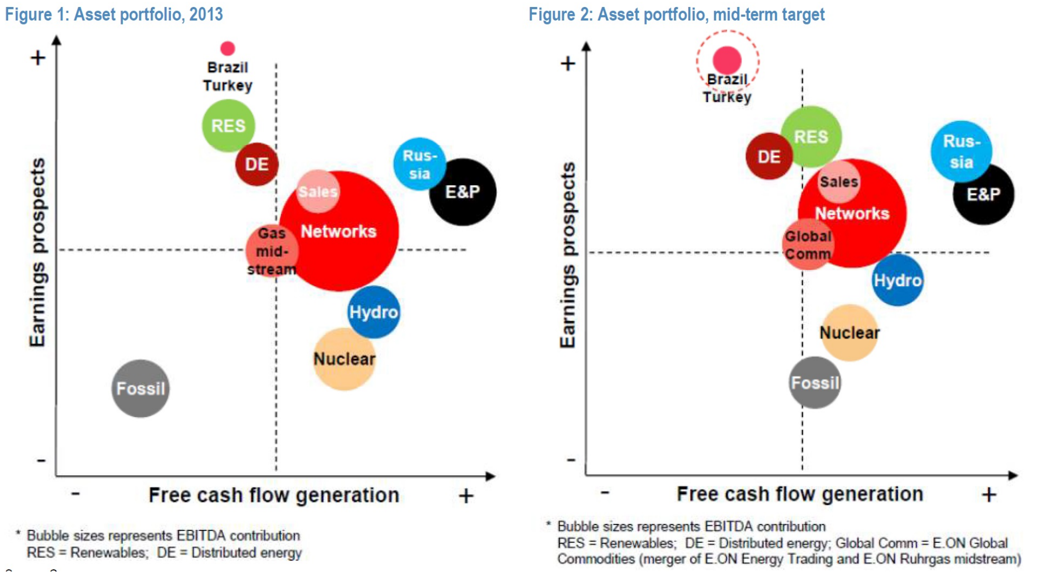
See figure 3.13.5.

3.13.8 Event studies

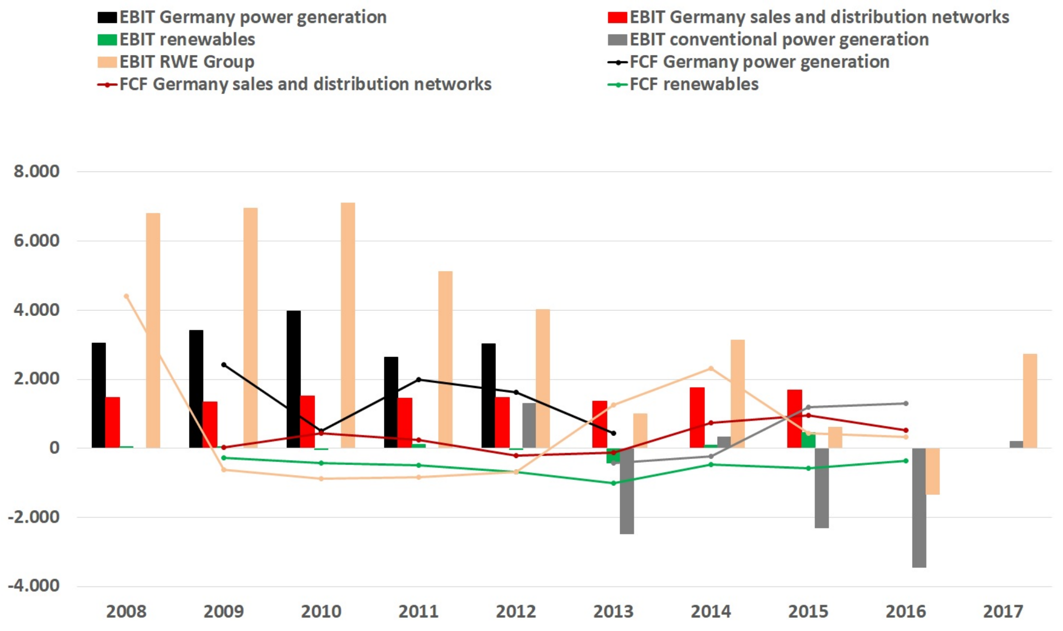
3.13.8.1 Share price event study

Estimation strategy Following MacKinlay (1997) and Kothari and Warner (2007), the market model is defined as follows: $R_{i,t} = \frac{P_{i,t}-P_{i,t-1}}{P_{i,t-1}}$
$R_{i,t} = \alpha_i + \beta_i R_{m,t} + \epsilon_{i,t}$
$E(\epsilon_{i,t}) = 0$
$\text{var}(\epsilon_{i,t}) = \sigma^2_{\epsilon_t}$
where $P_{i,t}$ are the period-t share prices and $R_{i,t}$ and $R_{m,t}$ the period-t returns of firm i (EON or RWE) and the market portfolio, respectively. ϵ_i, t is the the zero mean disturbance term. α_i, β_i and $\sigma^2_{\epsilon_t}$ are the parameters of the market model. Following the literature in using a broad based stock index, the Stoxx Europe 600 index as of November 2018 is used for the market portfolio.
The predicted return for a firm for a day in the event period is thus given by the estimation of this market model during a normal period defined as $N = 100$, i.e. day -101 to -1 prior to the event day:
$\hat{R}_{i,t} = \hat{\alpha}_i + \hat{\beta}_i R_{m,t}$
Then the abnormal returns of each firm i = EON, RWE on the event day, $t = 0$, is calculated:
$r_{i,t} = R_{i,t} - \hat{R}_{i,t}$
The relatively short normal and event periods are justified by the fast succession of events especially in 2015 and 2016, but results are largely robust to longer periods of up to 200 and 40 days for the normal and event period respectively.
If returns are normally, identically and independently distributed, then
$\frac{r_{i,t}}{\hat{s}(r_i)}$
has a t-distribution, with $\hat{s}(r_i) = \frac{1}{N-1}\sum_{t=-N-1}^{t=-1}(r_{i,t} - \bar{r}_i)^2$ being the standard deviation of the residuals over the normal period prior to the event day.

Regression results See table 3.6.

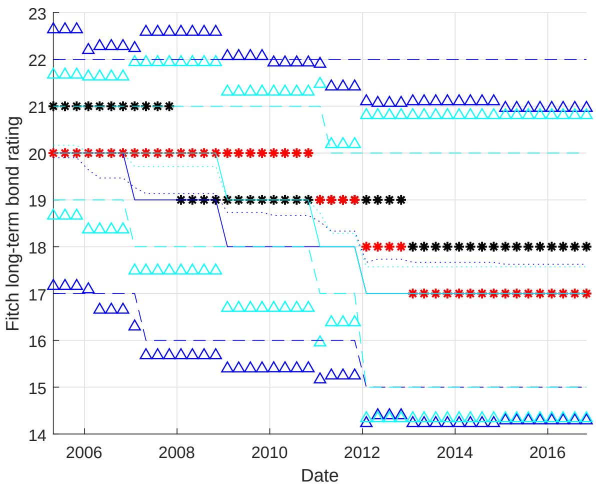


(a) EON EBITDA contributions, free cash flow generation and earning prospects. Source: JP Morgan 2013 from EON.

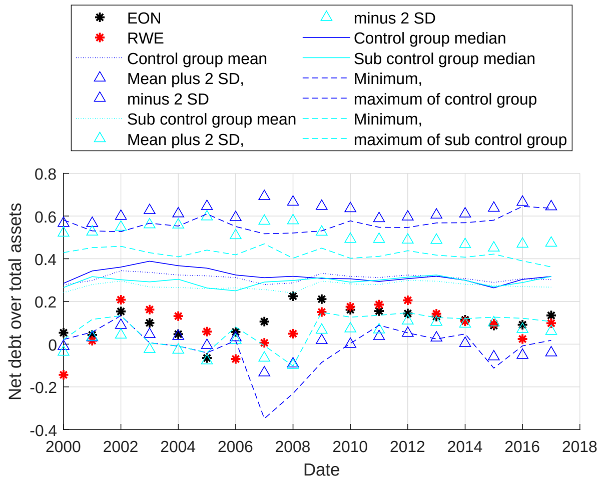


(b) RWE EBIT and free cash flows in the main segments in EUR million. In contrast to adjusted numbers that exclude "non-operational effects", e.g. impairments, this is an estimation of the unadjusted EBIT = adjusted EBITDA - (operating depreciation + amortisation) - impairments. Source: Own calculation and illustration, data from RWE annual reports.

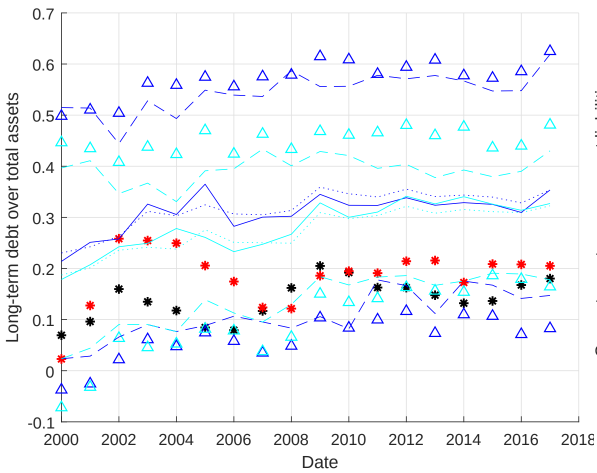
Figure 3.13.3: Illustrations of value creation and potential by segments at EON and RWE.



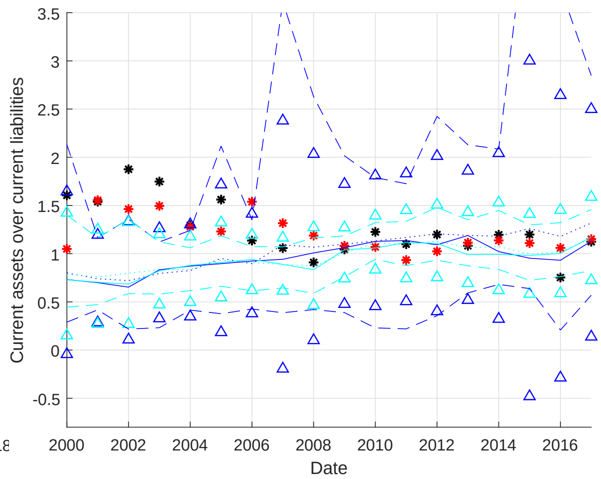
(a) Long-term bond rating as provided by Fitch. AAA = 24, DDD = 1.



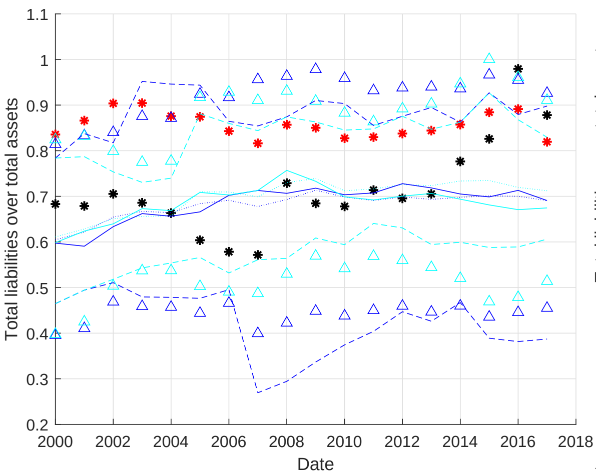
(b) Net debt over total assets. Net debt is total debt minus cash and short-term investments.



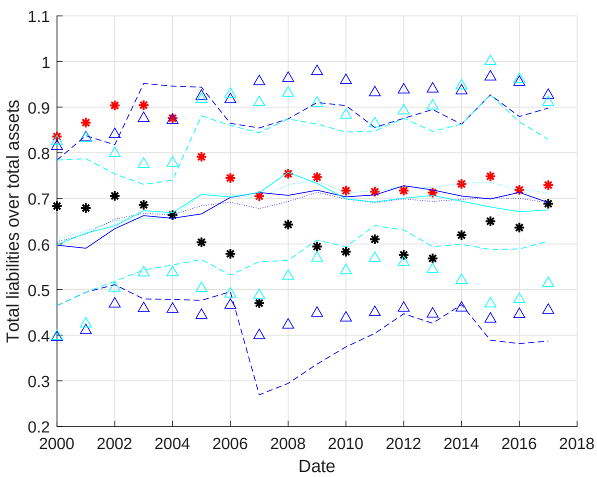
(c) Long-term debt over total assets.



(d) Liquidity ratio: current assets over current liabilities.



(e) Total liabilities over total assets.



(f) Total liabilities and, for EON and RWE, total liabilities less provisions for nuclear dismantling and storage over total assets.

Figure 3.13.4: Leverage and liquidity indicators. Source: Own calculation and illustration, data by Thomson Reuters Datastream.

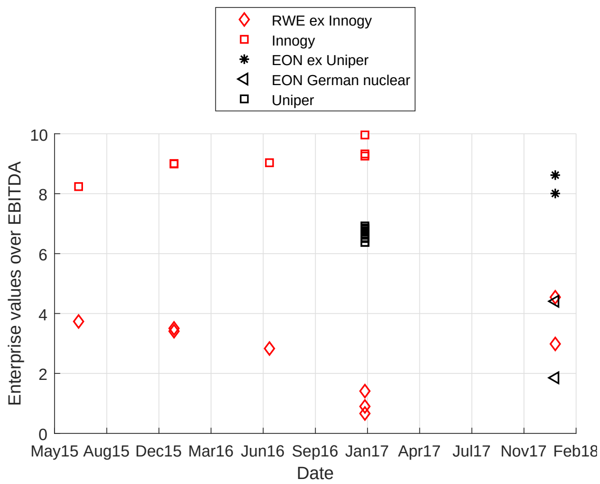


Figure 3.13.5: JP Morgan's estimates for enterprise value over EBITDA based on reports between May 2014 and June 2017. Source: Own illustration based on J.P. Morgan Cazenove (2014-2017).

Table 3.6: Regression results for share price event study. Two-sided t-test, * p<0.10, ** p<0.05, *** p<0.01. Normal period is 100 days prior to event day, event period is the event day. Type refers to the type of event: RE = renewable energy, N = nuclear policy, C = climate policy, D = divestiture related.

Event date t	Description	Source	Type	Exp. effect	α_{EON}	β_{EON}	R^2_{EON}	$\hat{s}(r_{\text{EON}})$	$r_{\text{EON},t}$	α_{RWE}	β_{RWE}	R^2_{RWE}	$\hat{s}(r_{\text{RWE}})$	$r_{\text{RWE},t}$
28-Jan-2013	Minister for the Environment, Altmaier, publishes proposal to cap renewable energy subsidy cost.	Handelsblatt (2013-01)	RE	+	-0.004	0.676	10.01%	0.013	-0.013	-0.003	0.770	18.65%	0.011	-0.004
9-Nov-2013	Agreement in CDU-SPD coalition talks on measures to cap renewable energy support costs.	Handelsblatt (2013-11)	RE	+	0.000	0.676	10.39%	0.014	0	0.000	0.605	4.69%	0.019	-0.002
21-Jan-2014	Measures to cap renewable energy costs are further specified by Ministry of Economic Affairs and Energy.	Gabriel (2014)	RE	+	0.001	0.798	10.45%	0.013	-0.003	0.002	0.793	5.81%	0.018	-0.001
5-May-2014	Handelsblatt reports on speech draft by environmental ministry executive saying that nuclear provisions will be examined soon.	Stratmann (2014)	N	-	-0.001	0.834	31.59%	0.009	-0.003	-0.000	0.835	18.41%	0.014	-0.004

Table 3.6: Regression results for share price event study. Two-sided t-test, * p<0.10, ** p<0.05, *** p<0.01. Normal period is 100 days prior to event day, event period is the event day. Type refers to the type of event: RE = renewable energy, N = nuclear policy, C = climate policy, D = divestiture related.

Event date t	Description	Source	Type	Exp. effect	α_{EON}	β_{EON}	R^2_{EON}	$\hat{s}(r_{\text{EON}})$	$r_{\text{EON},t}$	α_{RWE}	β_{RWE}	R^2_{RWE}	$\hat{s}(r_{\text{RWE}})$	$r_{\text{RWE},t}$
11-May-2014	Utilities suggest government-run nuclear fund that takes over all operationial, dismantling and storage related tasks in exhange for dropping various lawsuits against the government worth around EUR 15 billion.	Spiegel (2014), Dohmen and Hawranek (2014)	N	+	0.000	0.882	32.02%	0.010	0	0.000	0.879	18.64%	0.014	-0.011
27-Jun-2014	Bundestag decides on renewable energy law reform (EEG 2014) capping renewables subsidy cost.	BMWi (2014-06)	RE	+	0.001	0.863	24.55%	0.010	0	0.001	0.874	16.04%	0.013	0.013
23-Nov-2014	Minister in charge of energy, Gabriel, presents idea for CO2 reduction contribution by coal power plants.	Handelsblatt (2014-11)	C	-	-0.001	1.223	57.72%	0.010	0.002	-0.001	1.341	52.35%	0.012	0.003

Table 3.6: Regression results for share price event study. Two-sided t-test, * p<0.10, ** p<0.05, *** p<0.01. Normal period is 100 days prior to event day, event period is the event day. Type refers to the type of event: RE = renewable energy, N = nuclear policy, C = climate policy, D = divestiture related.

Event date t	Description	Source	Type	Exp. effect	α_{EON}	β_{EON}	R^2_{EON}	$\hat{s}(r_{\text{EON}})$	$r_{\text{EON},t}$	α_{RWE}	β_{RWE}	R^2_{RWE}	$\hat{s}(r_{\text{RWE}})$	$r_{\text{RWE},t}$
30-Nov-2014	E.ON announces to split off Uniper.	Drozdiak (2014)	D	+	0.000	1.237	54.68%	0.010	0.041***	-0.001	1.352	49.03%	0.012	0.014
17-Dec-2014	Süddeutsche Zeitung learns that state-run fund with 17 bn is planned according to ministries. Fund should solely secure funds but not take any operational or other liabilities.	Handelsblatt (2014-12)	N	-	0.000	1.182	51.86%	0.011	0.012	-0.001	1.336	51.63%	0.013	0.013
20-Mar-2015	Report written by consultancy Becker Büttner Held for Ministry of Economic Affairs concludes according to Handelsblatt that provisions are only safe if moved into external fund.	Handelsblatt (2015)	N	-	-0.001	0.989	36.62%	0.013	0.015	-0.003	1.030	29.98%	0.016	-0.002

Table 3.6: Regression results for share price event study. Two-sided t-test, * p<0.10, ** p<0.05, *** p<0.01. Normal period is 100 days prior to event day, event period is the event day. Type refers to the type of event: RE = renewable energy, N = nuclear policy, C = climate policy, D = divestiture related.

Event date t	Description	Source	Type	Exp. effect	α_{EON}	β_{EON}	R^2_{EON}	$\hat{s}(r_{\text{EON}})$	$r_{\text{EON},t}$	α_{RWE}	β_{RWE}	R^2_{RWE}	$\hat{s}(r_{\text{RWE}})$	$r_{\text{RWE},t}$
21-Mar-2015	Secretary of State for Energy, Baake, publishes paper on how coal power plants should contribute to climate policy via a proposed CO2 levy.	Frese (2015)	C	-	-0.001	0.980	35.47%	0.013	-0.005	-0.003	1.016	28.94%	0.016	-0.007
11-Jun-2015	Tagesschau reports on letter by CDU against the planned CO2 levy.	Mayer-Rüth (2015)	C	+	-0.001	0.871	27.20%	0.012	-0.016	-0.002	0.992	27.52%	0.014	-0.011
24-Jun-2015	Tagesschau reports on the failure of an agreement on a CO2 levy and instead the granting of compensation payments to lignite power plant operators.	Tagesschau (2015)	C	+	-0.001	0.911	29.85%	0.012	-0.001	-0.003	1.053	34.55%	0.013	0.025***
2-Jul-2015	Government publishes compromise on CO2 levy.	Flauger (2015-07)	C	+	-0.001	0.909	32.59%	0.012	0.018	-0.002	0.970	33.59%	0.013	0.058***

Table 3.6: Regression results for share price event study. Two-sided t-test, * p<0.10, ** p<0.05, *** p<0.01. Normal period is 100 days prior to event day, event period is the event day. Type refers to the type of event: RE = renewable energy, N = nuclear policy, C = climate policy, D = divestiture related.

Event date t	Description	Source	Type	Exp. effect	α_{EON}	β_{EON}	R^2_{EON}	$\hat{s}(r_{\text{EON}})$	$r_{\text{EON},t}$	α_{RWE}	β_{RWE}	R^2_{RWE}	$\hat{s}(r_{\text{RWE}})$	$r_{\text{RWE},t}$
28-Jul-2015	Leak of paper by Professors Irrek and Vorfeld casts doubt on security of nuclear provisions.	Süddeutsche Zeitung (2015)	N	-	-0.001	0.895	42.58%	0.011	-0.004	-0.002	0.948	36.07%	0.013	-0.006
9-Sep-2015	EON announces to keep nuclear segment.	Vasagar (2015)	D/N	-	-0.003	0.861	55.56%	0.011	-0.024***	-0.005	0.919	38.77%	0.017	-0.021
10-Sep-2015	Supervisory board agrees to keep nuclear with EON.	Bayernkurier (2015)	D	-	-0.003	0.845	53.93%	0.011	-0.058***	-0.005	0.905	38.04%	0.017	-0.021
11-Sep-2015	Handelsblatt first writes about Warth and Klein report, which will examine whether discount rate used for nuclear provisions is too high.	Flauger (2015-09)	N	-	-0.003	0.877	50.12%	0.013	-0.029***	-0.005	0.915	38.36%	0.017	-0.023

Table 3.6: Regression results for share price event study. Two-sided t-test, * p<0.10, ** p<0.05, *** p<0.01. Normal period is 100 days prior to event day, event period is the event day. Type refers to the type of event: RE = renewable energy, N = nuclear policy, C = climate policy, D = divestiture related.

Event date t	Description	Source	Type	Exp. effect	α_{EON}	β_{EON}	R^2_{EON}	$\hat{s}(r_{\text{EON}})$	$r_{\text{EON},t}$	α_{RWE}	β_{RWE}	R^2_{RWE}	$\hat{s}(r_{\text{RWE}})$	$r_{\text{RWE},t}$
15-Sep-2015	Spiegel leaks information on draft Warth and Klein study conclusions allegedly identifying a EUR 30bn nuclear funding gap.	Dohmen (2015)	N	-	-0.004	0.879	49.67%	0.013	-0.066***	-0.005	0.934	39.59%	0.017	-0.035***
17-Sep-2015	After pressure from all four utilities, minister in charge of energy, Gabriel, denies Warth and Klein conclusions. RWE is in talks for capital injection with Abu Dhabi investment firm.	Dohmen and Schießl (2015-09-19)	N	+	-0.005	0.802	34.43%	0.016	0.082***	-0.006	0.893	34.11%	0.018	0.099***
5-Oct-2015	Duin, economy minister of utilities' home state North-Rhine Westphalia, demands to cap nuclear liabilities in order not to endanger utilities.	Welt (2015)	N	+	-0.004	0.879	32.23%	0.019	0.016	-0.006	0.917	24.65%	0.024	0.053***

Table 3.6: Regression results for share price event study. Two-sided t-test, * p<0.10, ** p<0.05, *** p<0.01. Normal period is 100 days prior to event day, event period is the event day. Type refers to the type of event: RE = renewable energy, N = nuclear policy, C = climate policy, D = divestiture related.

Event date t	Description	Source	Type	Exp. effect	α_{EON}	β_{EON}	R^2_{EON}	$\hat{s}(r_{\text{EON}})$	$r_{\text{EON},t}$	α_{RWE}	β_{RWE}	R^2_{RWE}	$\hat{s}(r_{\text{RWE}})$	$r_{\text{RWE},t}$
8-Oct-2015	Publication of stress test (Warth and Klein) report with main conclusion that firms set aside enough nuclear decommissioning funds.	Copley and Eckert (2015)	N	+	-0.003	0.904	32.83%	0.020	0.005	-0.005	0.980	25.87%	0.025	0.005
1-Dec-2015	RWE announces to split off Innogy.	Terium and Günther (2015)	D	+	-0.003	0.938	27.53%	0.022	0.013	-0.005	1.134	21.38%	0.032	0.165***
27-Apr-2016	Commission unveils plans for utilities to pay EUR 23.3bn towards the cost of storing nuclear waste in exchange for a cap on storage liabilities. It is expected that the government follows the recommendation.	Financial Times (2016)	N	+/-	0.002	1.245	49.14%	0.018	0.031*	0.002	1.075	27.02%	0.026	0.053***

Table 3.6: Regression results for share price event study. Two-sided t-test, * p<0.10, ** p<0.05, *** p<0.01. Normal period is 100 days prior to event day, event period is the event day. Type refers to the type of event: RE = renewable energy, N = nuclear policy, C = climate policy, D = divestiture related.

Event date t	Description	Source	Type	Exp. effect	α_{EON}	β_{EON}	R^2_{EON}	$\hat{s}(r_{\text{EON}})$	$r_{\text{EON},t}$	α_{RWE}	β_{RWE}	R^2_{RWE}	$\hat{s}(r_{\text{RWE}})$	$r_{\text{RWE},t}$
12-Sep-2016	EON's subsidiary Uniper is first listed in a spin-off to existing shareholders.	Steitz and Schütze (2016)	D	+/-	-0.001	1.121	48.27%	0.015	-0.014	0.002	1.308	38.10%	0.022	-0.007
7-Oct-2016	RWE's subsidiary Innogy is first listed in an IPO including an equity increase.	Steitz (2016-10)	D	+/-	-0.002	1.127	51.63%	0.014	0.037***	0.002	1.327	48.53%	0.018	-0.07***

Addition to abnormal returns	EON			RWE		
	*	**	***	*	**	***
0	8.57%	5.43%	3.43%	7.14%	5.71%	3.43%
0.02	38.57%	29.43%	13.14%	33.14%	19.43%	6.57%
0.05	95.43%	92.86%	80.29%	83.14%	76.57%	62.00%

Table 3.7: Brown Warner simulation for share price event study. Percentage of significant regression results of 350 two-sided t-tests for event dates drawn randomly from t = [01-Jan-2013; 07-Oct-2016], * p<0.10, ** p<0.05, *** p<0.01. Normal period is 100 days prior to event day, event period is the event day.

Brown Warner simulation See table 3.7.

3.13.8.2 Trading volume event study

Estimation strategy Following the estimation strategy for the share price return market model, the market model for the trading volume data is defined as follows:

$V_{i,t} = \frac{T_{i,t} - T_{i,t-1}}{T_{i,t-1}}$

$V_{i,t} = \alpha_i + \beta_i V_{m,t} + \epsilon_{i,t}$

$E(\epsilon_{i,t}) = 0$

$\text{var}(\epsilon_{i,t}) = \sigma^2_{\epsilon_t}$

where $T_{i,t}$ are the period-t numbers of stocks traded and $V_{i,t}$ and $V_{m,t}$ the period-t changes of firm i's (EON's or RWE's) and the market portfolio's trading volume, respectively. ϵ_i, t is the the zero mean disturbance term. α_i, β_i and $\sigma^2_{\epsilon_t}$ are the parameters of the market model. In absence of a broad based index for stock trading volume data, the sum of the trades of all Stoxx 600 Europe Utilities components (see 3.13.2.2) is used as the market portfolio.

The predicted change in trading volume for a firm for a day in the event period is thus given by the estimation of this market model during a normal period defined as $N = 100$, i.e. day -101 to -1 prior to the event day:

$\hat{V}_{i,t} = \hat{\alpha}_i + \hat{\beta}_i V_{m,t}$

Then the abnormal change in trading volume of each firm i = EON, RWE on the event day, $t = 0$, is calculated:

$v_{i,t} = V_{i,t} - \hat{V}_{i,t}$

If returns are normally, identically and independently distributed, then

$\frac{v_{i,t}}{\hat{s}(v_i)}$

has a t-distribution, with $\hat{s}(v_i) = \frac{1}{N-1} \sum_{t=-N-1}^{t=-1} (v_{i,t} - \bar{v}_i)^2$ being the standard deviation of the residuals over the normal period prior to the event day.

Regression results See table 3.8.

Table 3.8: Regression results for trading volume event study. Two-sided t-test, * p<0.10, ** p<0.05, *** p<0.01. Normal period is 100 days prior to event day, event period is the event day. Type refers to the type of event: RE = renewable energy, N = nuclear policy, C = climate policy, D = divestiture related.

Event date t	Description	Source	Type	Exp. effect	α_{EON}	β_{EON}	R^2_{EON}	$\hat{s}(\upsilon_{\text{EON}})$	$\upsilon_{\text{EON},t}$	α_{RWE}	β_{RWE}	R^2_{RWE}	$\hat{s}(\upsilon_{\text{RWE}})$	$\upsilon_{\text{RWE},t}$
28-Jan-2013	Minister for the Environment, Altmaier, publishes proposal to cap renewable energy subsidy cost.	Handelsblatt (2013-01)	RE	+	0.17	1.41	0.11	1.10	-0.5	0.24	1.39	0.12	1.01	-0.378
9-Nov-2013	Agreement in CDU-SPD coalition talks on measures to cap renewable energy support costs.	Handelsblatt (2013-11)	RE	+	0.15	0.37	0.03	0.76	0.611	0.26	-0.05	0.00	1.04	-0.346
21-Jan-2014	Measures to cap renewable energy costs are further specified by Ministry of Economic Affairs and Energy.	Gabriel (2014)	RE	+	0.20	0.43	0.03	0.87	-0.723	0.27	0.50	0.02	1.18	-1.207
5-May-2014	Handelsblatt reports on speech draft by environmental ministry executive saying that nuclear provisions will be examined soon.	Stratmann (2014)	N	-	0.15	0.49	0.03	0.74	-0.545	0.27	0.19	0.00	1.06	0.576

Table 3.8: Regression results for trading volume event study. Two-sided t-test, * p<0.10, ** p<0.05, *** p<0.01. Normal period is 100 days prior to event day, event period is the event day. Type refers to the type of event: RE = renewable energy, N = nuclear policy, C = climate policy, D = divestiture related.

Event date t	Description	Source	Type	Exp. effect	α_{EON}	β_{EON}	R^2_{EON}	$\hat{s}(v_{\text{EON}})$	$v_{\text{EON},t}$	α_{RWE}	β_{RWE}	R^2_{RWE}	$\hat{s}(v_{\text{RWE}})$	$v_{\text{RWE},t}$
11-May-2014	Utilities suggest government-run nuclear fund that takes over all operationial, dismantling and storage related tasks in exhange for dropping various lawsuits against the government worth around EUR 15 billion.	Spiegel (2014), Dohmen and Hawranek (2014)	N	+	0.14	0.50	0.03	0.75	0.435	0.30	0.12	0.00	1.07	-0.711
27-Jun-2014	Bundestag decides on renewable energy law reform (EEG 2014) capping renewables subsidy cost.	BMWi (2014-06)	RE	+	0.23	0.99	0.08	0.95	-0.669	0.33	0.92	0.04	1.22	0.003
23-Nov-2014	Minister in charge of energy, Gabriel, presents idea for CO2 reduction contribution by coal power plants.	Handelsblatt (2014-11)	C	-	0.38	1.01	0.02	1.93	-0.345	0.57	1.89	0.06	2.19	-0.312

Table 3.8: Regression results for trading volume event study. Two-sided t-test, * p<0.10, ** p<0.05, *** p<0.01. Normal period is 100 days prior to event day, event period is the event day. Type refers to the type of event: RE = renewable energy, N = nuclear policy, C = climate policy, D = divestiture related.

Event date t	Description	Source	Type	Exp. effect	α_{EON}	β_{EON}	R^2_{EON}	$\hat{s}(\upsilon_{\text{EON}})$	$\upsilon_{\text{EON},t}$	α_{RWE}	β_{RWE}	R^2_{RWE}	$\hat{s}(\upsilon_{\text{RWE}})$	$\upsilon_{\text{RWE},t}$
30-Nov-2014	E.ON announces to split off Uniper.	Drozdiak (2014)	D	+	0.38	1.22	0.03	1.93	12.353***	0.61	2.04	0.07	2.21	-0.173
17-Dec-2014	Süddeutsche Zeitung learns that state-run fund with 17 bn is planned according to ministries. Fund should solely secure funds but not take any operational or other liabilities.	Handelsblatt (2014-12)	N	-	0.49	0.82	0.01	2.30	0.018	0.62	1.81	0.05	2.24	-0.603
20-Mar-2015	Report written by consultancy Becker Büttner Held for Ministry of Economic Affairs concludes according to Handelsblatt that provisions are only safe if moved into external fund.	Handelsblatt (2015)	N	-	0.37	0.55	0.01	1.68	0.151	0.41	0.64	0.01	1.41	-0.5

Table 3.8: Regression results for trading volume event study. Two-sided t-test, * p<0.10, ** p<0.05, *** p<0.01. Normal period is 100 days prior to event day, event period is the event day. Type refers to the type of event: RE = renewable energy, N = nuclear policy, C = climate policy, D = divestiture related.

Event date t	Description	Source	Type	Exp. effect	α_{EON}	β_{EON}	R^2_{EON}	$\hat{s}(\upsilon_{\text{EON}})$	$\upsilon_{\text{EON},t}$	α_{RWE}	β_{RWE}	R^2_{RWE}	$\hat{s}(\upsilon_{\text{RWE}})$	$\upsilon_{\text{RWE},t}$
21-Mar-2015	Secretary of State for Energy, Baake, publishes paper on how coal power plants should contribute to climate policy via a proposed CO2 levy.	Frese (2015)	C	-	0.38	0.54	0.01	1.68	-0.329	0.42	0.60	0.01	1.40	0.501
11-Jun-2015	Tagesschau reports on letter by CDU against the planned CO2 levy.	Mayer-Rüth (2015)	C	+	0.21	0.94	0.06	0.99	0.912	0.34	0.96	0.05	1.19	-0.878
24-Jun-2015	Tagesschau reports on the failure of an agreement on a CO2 levy and instead the granting of compensation payments to lignite power plant operators.	Tagesschau (2015)	C	+	0.21	0.91	0.06	0.99	0.949	0.35	1.08	0.05	1.22	2.568***
2-Jul-2015	Government publishes compromise on CO2 levy.	Flauger (2015-07)	C	+	0.21	0.79	0.05	0.93	0.296	0.36	0.94	0.04	1.23	5.855***

Table 3.8: Regression results for trading volume event study. Two-sided t-test, * p<0.10, ** p<0.05, *** p<0.01. Normal period is 100 days prior to event day, event period is the event day. Type refers to the type of event: RE = renewable energy, N = nuclear policy, C = climate policy, D = divestiture related.

Event date t	Description	Source	Type	Exp. effect	α_{EON}	β_{EON}	R^2_{EON}	$\hat{s}(\upsilon_{\text{EON}})$	$\upsilon_{\text{EON},t}$	α_{RWE}	β_{RWE}	R^2_{RWE}	$\hat{s}(\upsilon_{\text{RWE}})$	$\upsilon_{\text{RWE},t}$
28-Jul-2015	Leak of paper by Professors Irrek and Vorfeld casts doubt on security of nuclear provisions.	Süddeutsche Zeitung (2015)	N	-	0.29	0.93	0.05	1.07	-0.569	0.40	0.60	0.01	1.36	-0.891
9-Sep-2015	EON announces to keep nuclear segment.	Vasagar (2015)	D/N	-	0.24	1.01	0.09	0.97	0.342	0.35	0.23	0.00	1.21	-0.579
10-Sep-2015	Supervisory board agrees to keep nuclear with EON.	Bayernkurier (2015)	D	-	0.24	1.04	0.09	0.97	5.944***	0.36	0.20	0.00	1.21	0.83
11-Sep-2015	Handelsblatt first writes about Warth and Klein report, which will examine whether discount rate used for nuclear provisions is too high.	Flauger (2015-09)	N	-	0.30	1.13	0.08	1.13	-0.464	0.37	0.23	0.00	1.21	-0.748

Table 3.8: Regression results for trading volume event study. Two-sided t-test, * p<0.10, ** p<0.05, *** p<0.01. Normal period is 100 days prior to event day, event period is the event day. Type refers to the type of event: RE = renewable energy, N = nuclear policy, C = climate policy, D = divestiture related.

Event date t	Description	Source	Type	Exp. effect	α_{EON}	β_{EON}	R^2_{EON}	$\hat{s}(\upsilon_{\mathrm{EON}})$	$\upsilon_{\mathrm{EON},t}$	α_{RWE}	β_{RWE}	R^2_{RWE}	$\hat{s}(\upsilon_{\mathrm{RWE}})$	$\upsilon_{\mathrm{RWE},t}$
15-Sep-2015	Spiegel leaks information on draft Warth and Klein study conclusions allegedly identifying a EUR 30bn nuclear funding gap.	Dohmen (2015)	N	-	0.29	1.16	0.08	1.13	0.969	0.37	0.25	0.00	1.21	2.811***
17-Sep-2015	After pressure from all four utilities, minister in charge of energy, Gabriel, denies Warth and Klein conclusions. RWE is in talks for capital injection with Abu Dhabi investment firm.	Dohmen and Schießl (2015-09-19)	N	+	0.30	1.22	0.09	1.13	-0.486	0.37	0.37	0.01	1.23	-0.428
5-Oct-2015	Duin, economy minister of utilities' home state North-Rhine Westphalia, demands to cap nuclear liabilities in order not to endanger utilities.	Welt (2015)	N	+	0.30	1.12	0.08	1.13	-0.495	0.32	0.33	0.01	1.13	-0.469

Table 3.8: Regression results for trading volume event study. Two-sided t-test, * p<0.10, ** p<0.05, *** p<0.01. Normal period is 100 days prior to event day, event period is the event day. Type refers to the type of event: RE = renewable energy, N = nuclear policy, C = climate policy, D = divestiture related.

Event date t	Description	Source	Type	Exp. effect	α_{EON}	β_{EON}	R^2_{EON}	$\hat{s}(v_{\text{EON}})$	$v_{\text{EON},t}$	α_{RWE}	β_{RWE}	R^2_{RWE}	$\hat{s}(v_{\text{RWE}})$	$v_{\text{RWE},t}$
8-Oct-2015	Publication of stress test (Warth and Klein) report with main conclusion that firms set aside enough nuclear decommissioning funds.	Copley and Eckert (2015)	N	+	0.26	0.94	0.06	1.05	-0.415	0.31	0.46	0.01	1.10	-0.923
1-Dec-2015	RWE announces to split off Innogy.	Terium and Günther (2015)	D	+	0.19	0.50	0.02	0.93	-0.207	0.28	-0.25	0.00	1.01	6.995***
27-Apr-2016	Commission unveils plans for utilities to pay EUR 23.3bn towards the cost of storing nuclear waste in exchange for a cap on storage liabilities. It is expected that the government follows the recommendation.	Financial Times (2016)	N	+/-	0.28	0.20	0.00	0.99	0.773	0.55	2.00	0.06	2.25	0.339

Table 3.8: Regression results for trading volume event study. Two-sided t-test, * p<0.10, ** p<0.05, *** p<0.01. Normal period is 100 days prior to event day, event period is the event day. Type refers to the type of event: RE = renewable energy, N = nuclear policy, C = climate policy, D = divestiture related.

Event date t	Description	Source	Type	Exp. effect	α_{EON}	β_{EON}	R^2_{EON}	$\hat{s}(v_{\text{EON}})$	$v_{\text{EON},t}$	α_{RWE}	β_{RWE}	R^2_{RWE}	$\hat{s}(v_{\text{RWE}})$	$v_{\text{RWE},t}$
12-Sep-2016	EON's subsidiary Uniper is first listed in a spin-off to existing shareholders.	Steitz and Schütze (2016)	D	+/-	0.30	0.22	0.01	1.31	3.738***	0.63	0.12	0.00	2.58	5.534***
7-Oct-2016	RWE's subsidiary Innogy is first listed in an IPO including an equity increase.	Steitz (2016-10)	D	+/-	0.29	0.22	0.01	1.25	2.959***	0.75	0.36	0.00	2.77	5.214*

Addition to abnormal change in volume	EON			RWE		
	*	**	***	*	**	***
0	6.29%	4.29%	3.43%	6.29%	3.43%	2.29%
2	60.57%	48.29%	30.00%	32.86%	20.86%	11.43%
5	100.00%	96.57%	89.71%	93.71%	87.14%	75.14%

Table 3.9: Brown Warner simulation for trading volume event study. Percentage of significant regression results of 350 two-sided t-tests for event dates drawn randomly from t = [01-Jan-2013; 07-Oct-2016], * p<0.10, ** p<0.05, *** p<0.01. Normal period is 100 days prior to event day, event period is the event day.

Brown Warner simulation See table 3.9.

Chapter 4

The impact of production and macroeconomic risk on wind power equity returns

An analysis from a financial investor's perspective

Abstract

Financial investors play an increasing role in the operational phase of renewable energy assets. As policy support is reduced and the sector matures, investors have to rely on more prudent modelling of their asset returns.

This paper analyses how German wind park equity returns react if production and macroeconomic factors are misestimated at acquisition. Specifically, four sources of risk are examined: production, power prices, inflation and interest rates. A discounted cash flow model with detailed cost and revenue data of existing German wind parks with feed-in tariff is used to test the sensitivity of shareholder payouts to these risk factors.

The results underline the importance of energy production and power prices: shareholder payout returns range from 2.8 to 10.1% and from 3.6 to 9.3% for a reasonable variation in production and power prices respectively. Inflation has a medium and ambiguous impact depending on the time frame that wind parks operate under the guaranteed feed-in tariff regime. A possible increase in interest rates plays only a limited negative role for existing German wind park equity returns. Several strategies are suggested to mitigate the identified risks, which will substantially increase in the coming years as governmental support policies are phased out.

The paper contributes to the energy economics and finance literature by presenting a financial investor perspective on production and macroeconomic risk in wind energy. To policy makers, the results offer a deeper understanding of equity investor needs in order to harvest their available capital for reaching renewable energy targets.

Key words— Renewable energy; wind; financial investors; DCF model; sensitivity analysis.

4.1 Introduction

Utilities have traditionally dominated investments in electricity assets in Europe. However, the growing market of renewable energy generation attracted new classes of investors in recent years. In Germany, almost one third of renewable generation assets were owned by retail investors and around 14% each by project developers, financial investors like banks and funds and industrial firms in 2016 (figure 4.1.1).

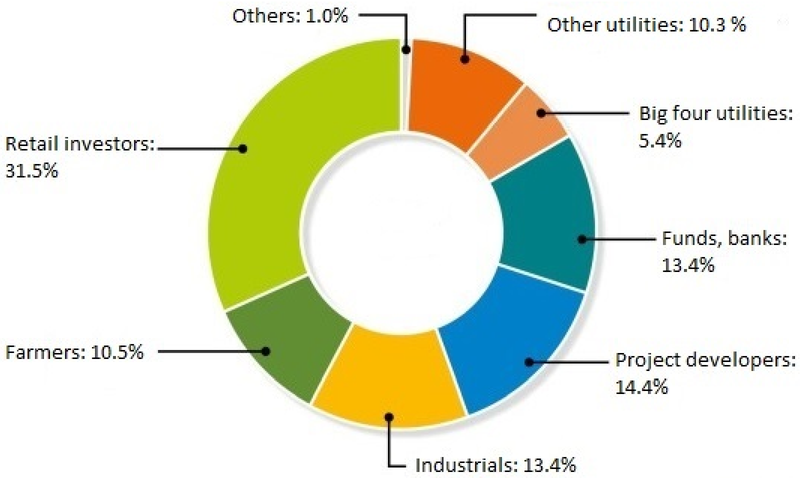


Figure 4.1.1: Owners of renewable energy assets in MW in Germany in 2016. Source: trend:research 2017.

Whereas project developers specialise in building renewable power plants and often sell them on to other investors after construction (Hostert 2016), the other investor types usually hold the assets longer-term, sometimes over their entire operational life of more than 20 years. Distressed utilities also discovered the build-sell-operate model as a way to recycle funds and generate profits by selling early-stage renewable assets to institutional investors (McCrone 2017). This explains the high share of financial investors in Germany, who usually do not develop projects themselves but enter after construction.

Institutional investors like pension funds and insurance companies allocate a growing part of their portfolios to renewable energies. In Europe, institutional investors' investments hit a record in 2017[1] of USD 9.9 billion, up 42% on 2016 (figure 4.1.2).

The attraction of renewable energies for institutional investors can be explained by the decentralised and relatively low-risk nature of renewable energy technologies compared to fossil fuels and nuclear, the low interest rate environment of the recent years, renewable energies' low correlation with capital markets and their relatively high returns while also being shielded from power price risk through governmental subsidy schemes (Ernst and Young 2014; Allianz 2017). Another factor was the weakening of traditional utilities in the face of low power prices, which opened a

[1] 2018 numbers are not available.

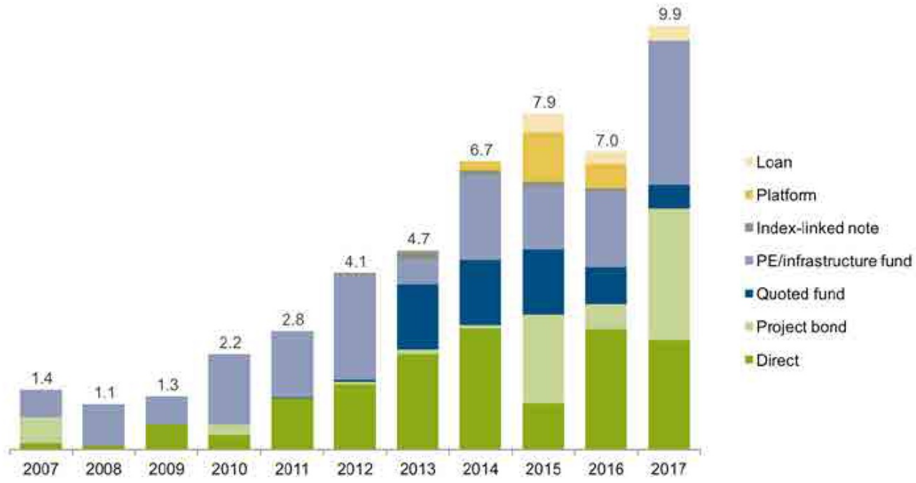


Figure 4.1.2: Institutional investor commitments to European renewable energy projects in USD billion. Source: Frankfurt School et al 2018.

niche for financial investors (Hörnlein 2019).

In recent years, with substantial experience gained in construction, management and financing of renewable energy, the sector matured and competition between investors increased. Moreover, in countries with fixed tariff regimes, the first power plants are approaching the end of their guaranteed feed-in tariff (FiT) period (of up to 20 years), whereas in other countries, subsidies have already been phased out.

As a result, project evaluation techniques are maturing as well. In a competitive environment asset managers have to accurately model asset returns in order to be able to offer a competitive price to project developers. On the other hand, they should not overpay for an asset and thereby impair their shareholders' returns.

In this context, it is critical for industry investors to understand the sensitivity of equity returns to variations in production and macroeconomic factors. This article offers a thought-experiment with data from four real onshore wind parks in Germany: a specialised asset manager, acting on behalf of an institutional shareholder, successfully bids for a wind park and acquires it from the project developer at start of operation. What is the effect on equity returns, if production and macroeconomic factors turn out to lie off the values estimated at acquisition?

Specifically, four sources of risk are examined. First, realised production in kilowatt-hours (kWh) is the biggest factor of uncertainty for any wind park. Second, for wind parks in Germany, market power prices are important after the guaranteed FiT period of 20 years. Third, inflation plays a role for power prices as well as operating costs, which are partly indexed. Fourth, after the end of the fixed interest period of their long-term loans, wind parks are exposed to interest rate risk. A discounted cash-flow model is used to examine how variations in these four risk factors impact equity returns.

The paper contributes to a better understanding of financial equity investors' needs and challenges. This understanding is crucial if policy makers want to harvest financial investors' available capital in order to reach ambitious renewable energy targets.
The paper is structured as follows. Section 4.2 explains how the article contributes to the existing academic literature. Section 4.3 lays out the research question and four related hypotheses. Section 4.4 states the model and section 4.5 gives details on all the model's inputs. Section 4.6 states the results of the paper and section 4.7 discusses their implications in more detail. Section 4.8 concludes.

4.2 Contribution to the literature

The paper builds on and contributes to three strands of the energy finance and economics literature:

1. **Literature on the relative importance and needs of different investor classes.** In recent years scholars have increasingly analysed the evolution of the energy sector in terms of different investor classes (e.g. Nelson and Pierpont 2013; Mazzucato and Semienuk 2018; Steffen 2018) and their needs in terms of risks and returns (e.g. Bürer and Wüstenhagen 2009; Gatzert and Kosub 2016; Salm and Wüstenhagen 2018). Researchers generally conclude that financial investors have become more important in Europe's renewable energy sector and that they might be well suited for the long-term nature of energy investing but less willing to take on construction or power price risk. The literature stays silent, though, on the specific way financial investors evaluate private equity investments in renewable energies and on the role that different cost and revenue items as well as macroeconomic expectations play. This paper adds by presenting a discounted cash flow model typically used by institutional investors to evaluate wind power plant acquisitions and by testing the sensitivity of equity return to different assumptions.

2. **Literature on the importance of the cost of capital for renewable energy investments.** This strand of literature looks at the role of financing costs for renewable energy investments. It is generally agreed that compared to conventional energy investments, where fuel costs occur over the lifetime of the projects, investment and therefore financing costs play a much larger role for renewable energy (Bean et al 2017, Monnin 2015, Ondraczek et al 2015, Wiser and Pickle 1998). In the past few years, both macroeconomic factors and experience contributed to bringing financing costs down (Egli, Steffen and Schmidt 2018). The current literature does not analyse the interplay of financial investors' cost of capital and how future macroeconomic developments influence the projects' economic viability, which will be this paper's

contribution.[2]

3. **Literature using investment models.** The last strand of literature is concerned with building investment models to evaluate renewable energy projects, e.g. Afanasyeva et al (2016), Diaz et al (2015), Kim et al (2017), Kitzing et al (2018), Levitt et al (2011), Santos et al (2017). However, these models have two shortcomings. First, most models do not analyse the sensitivity of the profitability to macroeconomic factors like inflation and interest rates. If they do, like Kaldellis and Gavras (2000), typically they do not use real macroeconomic forecasts but rather arbitrary values. Second, none of these models capture the reality of financial institutional investors like pension funds and insurances. These investors, or the asset managers acting on their behalf, have detailed knowledge of revenues and costs arising from contractual and other obligations, while academic research often captures these factors in a rather general and inaccurate manner. This paper is using revenues and costs from four real turn-key wind power projects. Another contribution of this paper is that it models the effects of production and macroeconomic risk on equity returns from the point of view of the shareholder instead of merely looking at overall project value or levelized cost of energy (LCOE), as most aforementioned studies do.

4.3 Research question and hypotheses

The research question of this paper is: to what extent do production uncertainty, power prices, inflation and interest rate dynamics affect a wind park shareholder's payout? The goal is to quantify the impact of these risks on equity returns of German wind assets acquired as turn-key projects using a discounted cash flow model.
The following effects are expected.

1. Higher **production** in terms of kilowatt-hours (kWh) leads to higher revenues and therefore ceteris paribus to a higher equity return. This is the case for the guaranteed feed-in tariff remuneration as well as for revenues from the market. In the case of the feed-in tariff, policy makers partly balance out low revenues due to unfavourable locations by a higher remuneration per kWh. A higher overall production means a lower FiT, albeit not fully compensating the quantity effect. Production is thus expected to have a positive impact on the equity return.

2. All four wind parks analysed receive a guaranteed remuneration in terms of EUR per kWh for 20 years. After that, higher wholesale **power prices** ceteris paribus lead to higher revenues, as

[2] One recent paper by Schmidt et al (2019) looks at the effect of interest rates on different renewable energy technologies in a more general manner and will be referred to in the section on interest rate assumptions.

power purchase agreements (PPAs) are assumed to be indexed to power prices. As an additional effect, high power prices could lead to an early switch from the fixed FiT remuneration to a PPA. Power prices are therefore expected to have a positive impact on equity returns.

3. **Inflation**[3] affects equity returns through two levers: first, a portion of operating cost is increasing with inflation due to indexed contracts. Second, revenues increase with inflation, insofar as one assumes that operators negotiate PPAs that are inflation-indexed. Feed-in tariffs, on the other hand, are not inflation-indexed.[4] Which effect dominates depends on the specific contractual arrangement of each wind park and on how long the wind park stays in the FiT regime. Inflation is therefore expected to have an ambiguous impact on equity returns.

4. Interest rates of the analysed wind parks are fixed for several years, after which they have to be renegotiated. Higher **interest rates** after the fixed-interest period are expected to have a negative impact on equity returns via higher interest payments.

4.4 Model

The goal of the analysis is to quantify the sensitivity of the payout return to different production (Q), power price (P), inflation (I) and interest rate (D) scenarios. A deterministic discounted cash-flow model is used, which is common practice in the renewable energy industry (Hürlimann 2018). The model is appropriate, inter alia, because renewable energy assets have a finite lifetime and because returns are determined by long-term trends for which stochastic estimates are generally not available (see also section 4.5.1). The model is implemented in Matlab R2019a.

Buy-and-hold risk-averse investors, like pension funds and insurances, typically buy turnkey or operational power plants to avoid construction risk. The model assumes such a long-term investor and therefore sets the acquisition date equal to the month prior to beginning of operation.

Equation 4.4.1 gives all components of monthly cash-flow to equity, whereas the four factors for which a sensitivity analysis will be performed are listed in brackets after each component that depends on any of those factors. Each of the components of cash-flow to equity is described in more

[3] Deflation is not ruled out, however, forecast ranges result in positive inflation values year-on-year.

[4] Indirectly, inflation also has an effect via its correlation with interest rates and power prices. Modelling this correlation, however, goes beyond the scope of this paper.

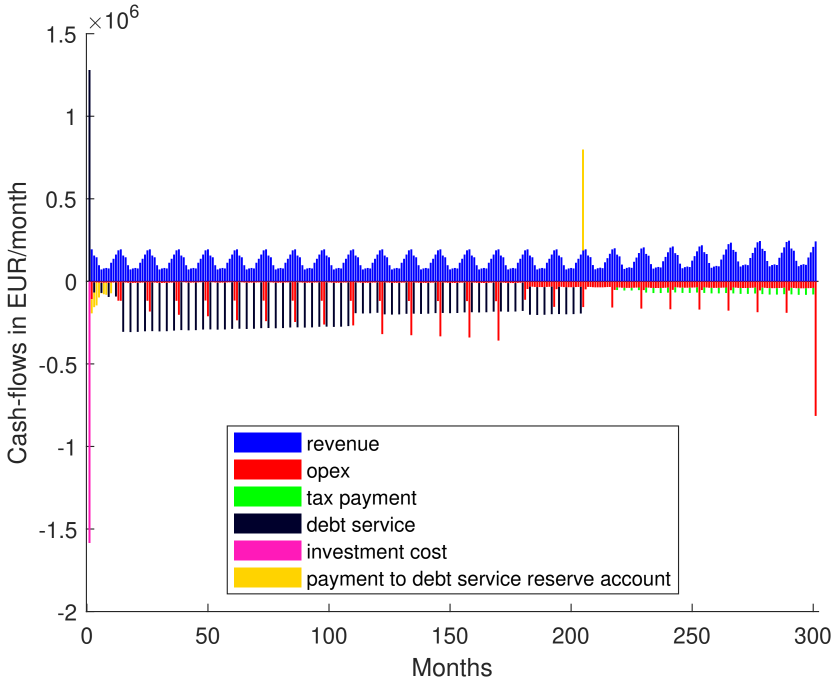


Figure 4.4.1: Revenue and cost components of cash-flow to equity in EUR/month for wind park 2. All values have been shrunk by factor 10 in the first month for illustration purposes.

detail in the next section.

$$\begin{aligned}\text{CF to equity}_m = \quad & \text{Revenue(Q, P)}_m - \text{Opex(Q, P, I)}_m - \text{Tax(Q, P, I, D)}_m - \text{Investment cost(Q, P, I, D)}_m \\ & - \text{Net debt service(D)}_m - \text{Reserve payments(Q, P, I, D)}_m\end{aligned} \tag{4.4.1}$$

with operating months $m = [0; 300]$. $m = 0$ is the acquisition date; $m = 1$ is the first and $m = 300$ the last month of operation.

Revenue(Q, P) is the revenue from the feed-in tariff and the PPA depending on the production of the wind farm Q in kWh and the power price P. Opex(Q, P, I) is operating cost depending on production in kWh (Q), power price (P) and inflation (I). Tax(Q, P, I, D) is the trade tax paid. It is calculated based on revenues less opex less depreciation less interest payment. Investment cost(Q, P, I, D) consists mainly of the acquisition price and various other transaction costs. The acquisition price is obtained endogenously by setting the required payout return to an exogenous hurdle rate. Net debt service (D) adds up all cash flows related to debt: disbursements of loans, redemption payments and interest cost, which depend on the redemption schedule, on the fixed rate and, after the fixed rate period, on the negotiated subsequent rate. Reserve payments (Q, P, I, D) are payments to the debt service reserve account. This account is required by the loan contracts and built up after serving opex, tax, investment cost and debt.

The components of the monthly cash-flow to equity can also be expressed in terms of cash-flows:

$$\text{Operating CF}(Q,P,I,D)_m = \text{Revenue}(Q,P)_m - \text{Opex}(Q,P,I)_m - \text{Tax}(Q,P,I,D)_m \tag{4.4.2}$$

$$\text{Investing CF}(Q,P,I,D)_m = -\text{Investment cost}(Q,P,I,D)_m \tag{4.4.3}$$

$$\text{Financing CF}(Q,P,I,D)_m = -\text{Net debt service}(D)_m - \text{Reserve payments}(Q,P,I,D)_m \tag{4.4.4}$$

Therefore

$$\text{CF to equity}(Q,P,I,D)_m = \text{Operating CF}(Q,P,I,D)_m + \text{Investing CF}(Q,P,I,D)_m + \text{Financing CF}(Q,P,I,D)_m \tag{4.4.5}$$

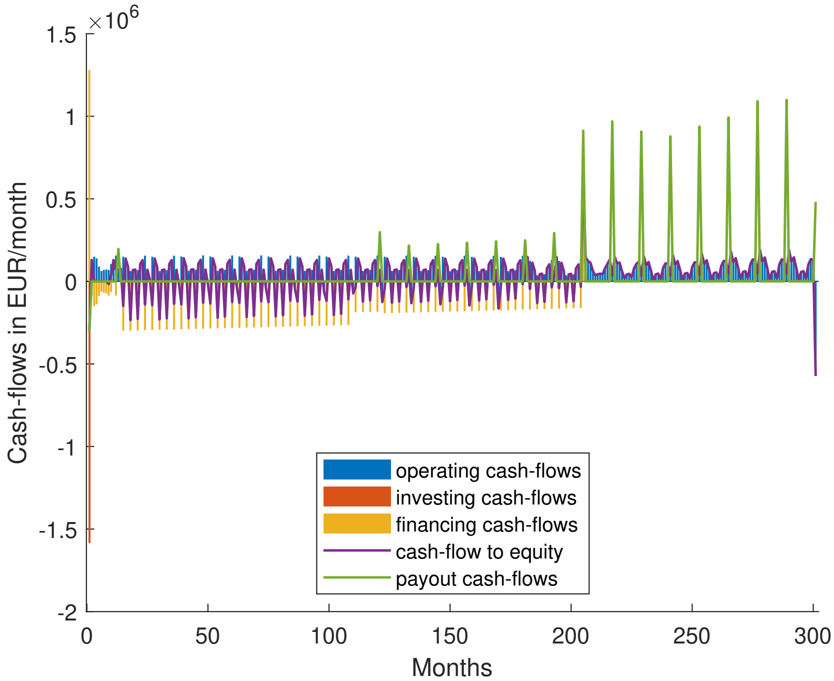


Figure 4.4.2: Main cash-flows and resulting cash-flow to equity and payout cash-flow in EUR/month for wind park 2. All values have been shrunk by factor 10 in the first month for illustration purposes.

Based on cash-flow to equity, one can calculate Payout_t, the payouts to equity holders at the end of each calendar year, where CF to equity_t is the sum of monthly cash-flows to equity over the preceding year.

$$\text{Payout carry forward}_t = \begin{cases} \text{CF to equity}_t & \text{if Payout carry forward}_{t+1} >= 0 \\ \text{CF to equity}_t + \text{Payout carry forward}_{t+1} & \text{if Payout carry forward}_{t+1} < 0 \end{cases} \tag{4.4.6}$$

$$\text{Payout}_t = \max(0, \text{Payout carry forward}_t) \tag{4.4.7}$$

Equation 4.4.7 can be solved with backwards induction. The relationship between cash-flow to equity and payout cash-flows is plotted in an illustrative way in figure 4.4.2.

The payouts are used in equation 4.4.8, which is solved for the acquisition price, a part of investment cost (see equation 4.4.1 on cash-flow to equity).

$$0 = \sum_{t=1}^{T} \text{Payout}_t \cdot (1 + \text{IRR})^{-t} \tag{4.4.8}$$

with operating years $t = [1; T]; T = 25$ where T is the lifetime of the plant fixed at 25 years and IRR is a hurdle rate fixed exogenously as well.

Equation 4.4.8 is first solved with all risk factors (Q, P, I, D) fixed at their median scenario. Then, the risk factors are varied each at a time, while the acquisition price calculated for the median scenario, the other risk factors and all other inputs are kept constant. Using up to equation 4.4.7, this yields a different payout time series for each scenario. Equation 4.4.8 is then solved again, but this time for IRR, given these different payout series. This yields a range of results for IRR depending on the scenario. The range of results is then used to evaluate the impact of the different risk factors on shareholder payout returns.

The model implicitly assumes that the bidding process is perfectly competitive and the investors offer the highest price possible still yielding their required equity payout return. This is done to ensure comparability between the four wind parks.

4.5 Model inputs

4.5.1 Scenarios

The scenarios are not modelled endogenously but taken from existing historical data and forecasts as long-term macroeconomic modelling lies beyond the scope of this paper.[5]

Since wind parks are long-lived, the model requires long-term forecasts of the four risk factors over the next 25 years. This is a time frame for which probabilistic modelling estimates are not available. Forecasts used therefore only contain expected values and no probabilistic estimates.

The following section describes the most pertinent forecasts for production, power prices and wind market values, inflation and interest. For each parameter, a median scenario is selected. Based on this, five scenarios are evaluated: first, the acquisition price is derived as described earlier for the

[5] For example, to endogenously derive future power prices one would require a fundamental model with detailed assumptions about governmental policies in terms of grid expansion, coal exit and renewables support as well as about private investment in and retirement of different types of power plants. To model future inflation and interest rates, one would require a macroeconomic model depicting different economic sectors and monetary policy.

median scenario. For this scenario, the payout return is by definition equal to the set hurdle rate. Then the sensitivity of the payout return is tested for the four remaining scenarios: maximum and minimum as well as two intermediate scenarios.

4.5.1.1 Production

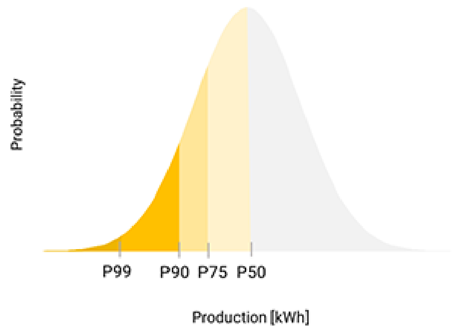


Figure 4.5.1: Illustration of P50, P75 and P90 values. Source: Solargis (2018).

Production uncertainty is a key source of risk for renewable energy assets. Unlike conventional power plants based on fossil fuels or nuclear, wind and solar plants' production is weather-dependent. In order to forecast the energy production at each site, at least one detailed wind assessment is part of every wind project development process. The assessments are also shared with the equity investors during the due diligence process before an acquisition. The production assumptions are directly taken from these wind assessments.

Wind assessments assume a normal distribution to describe production uncertainty and they report the long-term median energy production in kWh, or P50 value, and further percentiles like P75 and P90. P50 is exceeded with 50% likelihood, whereas P75 is a lower, more conservative value and exceeded with 75% likelihood, as illustrated in figure 4.5.1. For a risk-neutral investor one would thus use the P50 value plus/minus some variation. However, in reality, often P75 and sometimes even P90 is used. One reason is that as wind assessments are commissioned by project developers who then go on to sell their assets, there is a motivation to overestimate future production (Interview 2018, Interview 2019a). For this study, the minimum production scenario is therefore set at P90 and the maximum at P50, which conservatively assumes a median between the two.

The annual production is assumed to be constant over the parks' lifetime and to vary only between the different scenarios.[6] As the model works with monthly granularity, each month's production is calculated as a fixed percentage of the annual assumed production. This yields the well-known bell-shaped annual revenue curve that can be observed in figure 4.4.1.

The P-values used here are net of expected shut-downs due to bats or other protected animals as well as acoustic noise or shading. However, grid losses, technical unavailability and paragraph 51

[6]This is done for simplicity and comparability but of course in practice, production varies between years.

(EEG 2017)[7] are not considered, which is why the production scenarios are reduced by another 3%. This number is merely an educated guess but follows industry practice and has been confirmed with practitioners as reasonable (Interview 2018, Interview 2019b).

4.5.1.2 Power prices and wind market values

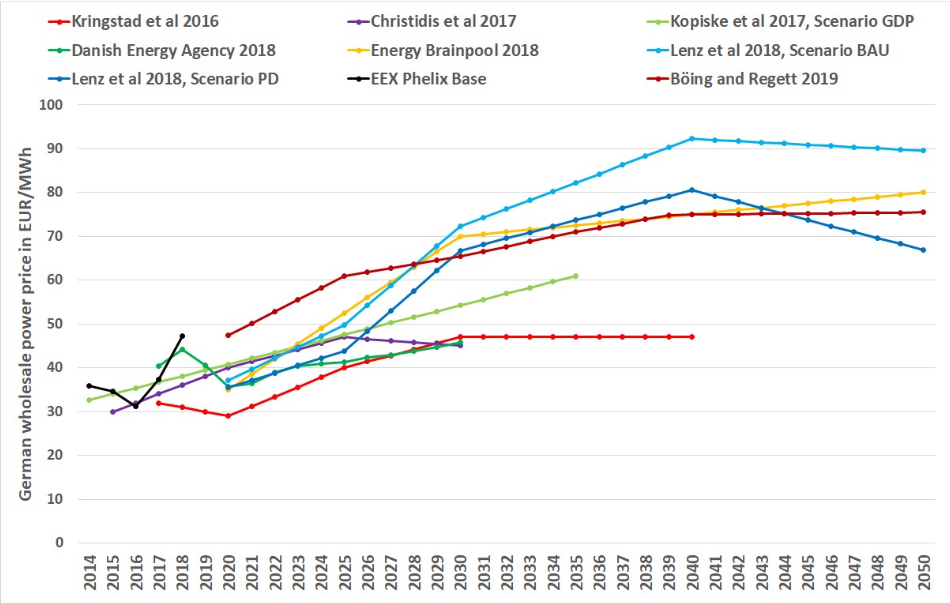
For future power prices, the academic and practitioners' literature of power wholesale price forecasts for Germany has been reviewed. Only forecasts published in 2016 or later were considered. Eight scenarios were identified, which are plotted in figure 4.5.2a.

Using the wholesale power price as an estimate for wind market prices would overstate revenues. This is due to the so-called cannibalisation effect, which is closely connected to the intermittent nature of renewable energy production described in the previous section. Since wind power production depends on the occurrence of wind, which is auto-correlated for different locations within one region like Germany, there tend to be times of overall high and low power production depending on the availability of wind. In times of strong wind, wholesale power prices decrease and vice versa. Since by definition wind parks produce more energy during high wind times, the average price they obtain on the market is below the average power price. This is expressed as the "market value" of wind, which is currently estimated at around 86% of average wholesale power prices in Germany (Hirth 2019).

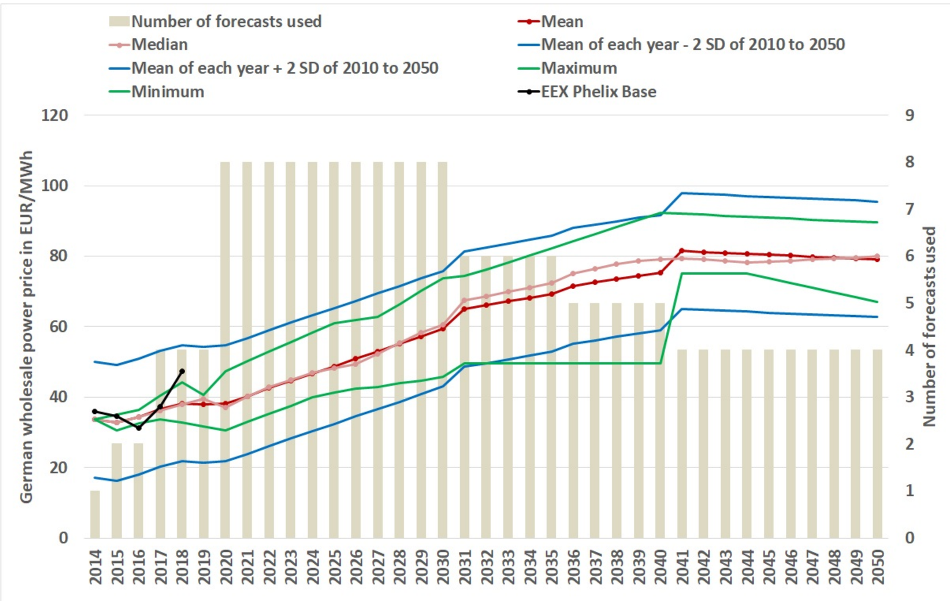
For future forecasts of market values, an average of Reeg (2019) and Böing and Regett (2019) is used, which results in a market value of 83% of the wholesale price for 2019, declining to 66% in 2042. All future power price scenarios from figure 4.5.2 are multiplied by these market values. As a maximum and minimum scenario the median of all market value forecasts plus/minus two standard deviations of the historical EEX Phelix baseload price between 2010 and 2018 is used.[8] Thus a range of scenarios of wind market values is obtained. These are used in the calculation of revenues as described in section 4.5.3.2.

[7] Paragraph 51 (EEG 2017) stipulates that if hourly spot prices are negative for at least six consecutive hours in the day-ahead auction, no remuneration is paid during this negative-price time period.

[8] The standard deviation is 7.76 EUR/MWh.



(a) Overview of all sources for power price forecasts and historical EEX Phelix Base for comparison in EUR/MWh.



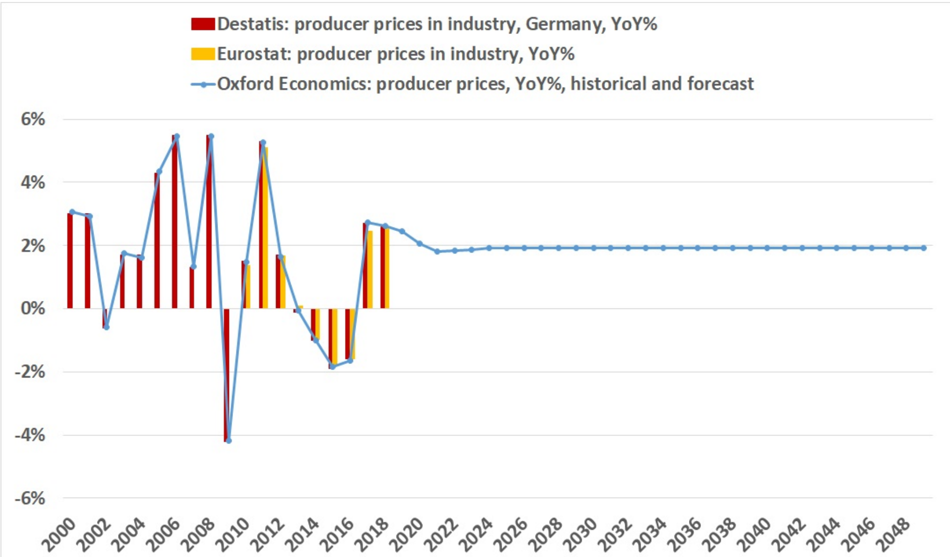
(b) Descriptive statistics of power price forecasts in EUR/MWh. (Historical EEX Phelix Base is not included in calculation of descriptive statistics.)

Figure 4.5.2: Power wholesale price forecasts for Germany in EUR/MWh.

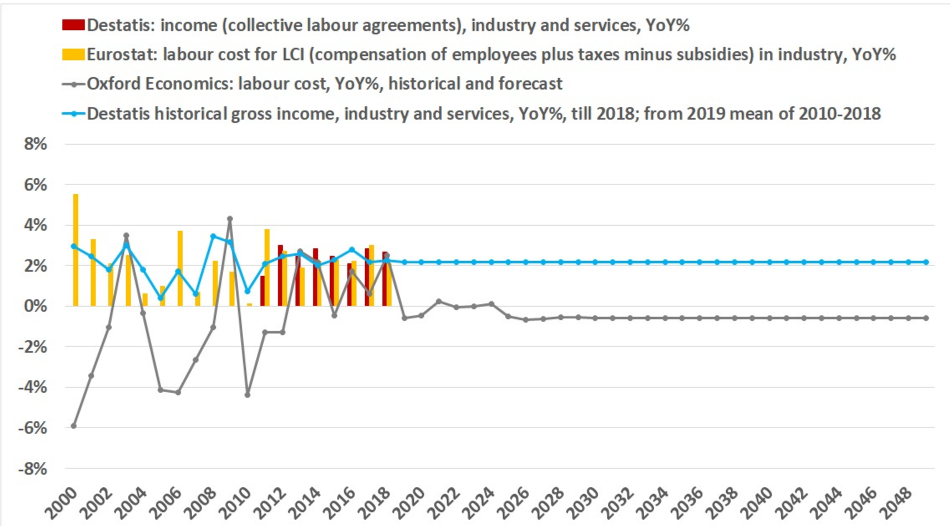
4.5.1.3 Inflation

Inflation increases market revenues as well as operating costs. The operation and maintenance (O&M) contract represents the largest amount explicitly indexed. The inflation indexes used in the contracts are a combination of producer prices and labour costs, of which the most common indexes used are plotted in figure 4.5.3.

Deflation is not ruled out. However, moderate forecasts are used in order to avoid results being driven by wide ranging assumptions. The forecasts used here result in only positive inflation values year-on-year.



(a) German producer price forecast and indexes in % year-on-year.



(b) German labour cost forecast and indexes in % year-on-year.

Figure 4.5.3: German inflation forecasts and indexes used in wind power service contracts in % year-on-year.

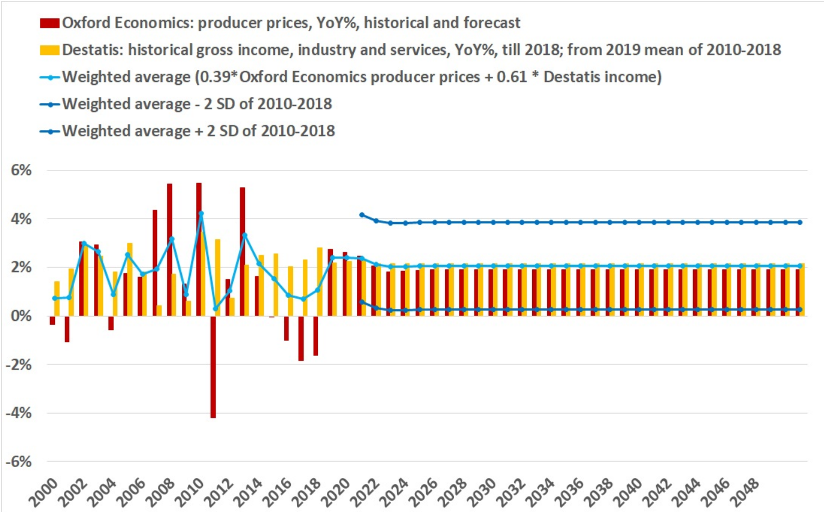


Figure 4.5.4: German inflation forecasts and indexes used for revenue and opex indexation in % year-on-year.

For producer prices, the Oxford Economics data[9] lie in a reasonable range where historical values track the actual indexes and forecast values are in line with past data (figure 4.5.3a). For labour cost, the only long-term forecast found is a general indicator of labour cost in Germany, which does not coincide with the historical data of the more sector specific industry labour cost. As a forecast, the Destatis index is therefore extrapolated by taking the mean of 2010 to 2018 (figure 4.5.3b).

The two forecasts are combined in figure 4.5.4 in a way that mirrors the wind park service contracts. Producer prices are weighted by 39% and labour cost by 61%, the average weighing in the four contracts. The maximum/minimum scenarios of inflation are set at this median plus/minus two times the average of the standard deviations of the historical weighted inflation rate from 2010 to 2018. This yields a long-term inflation range of 0.27 to 3.87% per year.

Power prices are a major driver of producer prices in the industrial sector (Destatis 2019). For simplicity and since producer prices and labour costs in the industrial sector have very similar forecasts, power prices are assumed to increase at the same rate as operating costs.

4.5.1.4 Interest

For interest rates, several historical time series from the European Central Bank were analysed (ECB 2019). The most pertinent ones, for corporate loans larger than EUR 1 million and with an initial rate fixed for five to over 10 years, are plotted in figure 4.5.5.

The Oxford Economics long-term data are historically slightly above the ECB values, which is why

[9] According to information by the consultancy, their "macroeconomic forecasts are done in a fully integrated global economic model, where individual country models are linked through assumptions about trade volume and prices, competitiveness, capital flows, interest and exchange rates and commodity prices. It is an eclectic model designed to capture the key relationships in the global economy so it is Keynesian in the short run and Monetarist in the long run" (Oxford Economics 2019). To the author's knowledge, whenever Oxford Economics data is used, no other publicly available long-term forecast data exist.

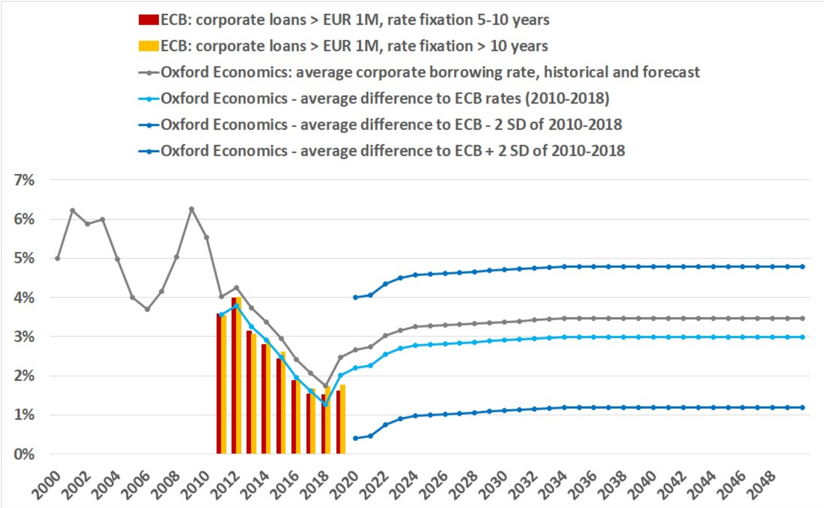


Figure 4.5.5: German interest forecasts and indexes used after the fixed interest period in % year-on-year.

the average difference to the two ECB rates from 2010 to 2018 is deducted from the Oxford forecast values from 2019 onwards. The maximum/minimum scenarios of inflation are set at this value plus/minus two times the average of the standard deviations of the two ECB rates from 2010 to 2018. This yields a long-term interest rate range of 1.19 to 4.78% per year. This is roughly in line with the scenarios tested in a recent study by Schmidt et al (2019).

Inflation and interest are in reality interdependent. Since macroeconomic modelling is beyond the scope of this paper, though, the problem is circumvented by using moderate ranges of scenarios for each inflation and interest rate and by fixing the respective other parameters at their median scenarios when testing the sensitivity of the payout return.

4.5.2 Hurdle rate

The hurdle rate is defined here as the required shareholder payout return. This number is necessary to be able to solve the model for the acquisition price and as a point of comparison for the different assumptions.

However, hurdle rates are considered confidential by financial investors. Therefore, the estimate used here is taken from two surveys. Egli, Steffen and Schmidt (2018) rely on interviews with financial lead arrangers of 80% of the German onshore wind investment sum between 2000 and 2017. They report the range of cost of equity for onshore wind parks at between 4 and 7.5% for 2017. Breitschopf et al (2016) rely on a model and only six interviewees, but their estimated range of 6 to 9.3% is more in line with what is currently reported by the industry (Metcalfe 2019; Fahrenholtz 2019). The median between the most extreme points of these two ranges yields an equity return hurdle rate of 6.65%.

The results of this paper are also tested for a payout return of 3% and 10% and they are qualitatively the same.

4.5.3 Wind park specific data

For all cash-flow components, real data of four wind parks is used. The data is obtained from the portfolio of an infrastructure fund focused on renewable energies. Individual wind park parameters cannot be revealed due to confidentiality, but the following section gives general information on all main parameters and the appendix (table 4.1) contains a list with means and standard deviations of the main parameters.

4.5.3.1 Wind park characteristics

In order to avoid comparability issues due to different renewable energy policies or tax regimes, the four wind power plants chosen are all located in Germany and built in 2017 and 2018. It is assumed that all four wind parks start operation on December 31, 2018, which is also the date of the acquisition by the financial investor. The lifetime is assumed to be 25 years, i.e. the wind parks stop operating on December 30, 2043. The wind parks are comparatively small with a nameplate capacity of between 4.7 and 9.9 MW each and 7.22 MW on average. Various turbine types and manufacturers are represented (Enercon, General Electric, Vestas).

4.5.3.2 Revenue

The revenue is given by

$$\text{Revenue}_m(\text{Q, P}) = \begin{cases} \text{Q}_m \cdot \max[\text{FiT}_m(Q), \text{Market value}_m(P, I)] & \text{if } m = [1;240] \\ \text{Q}_m \cdot \text{Market value}_m(P, I) & \text{if } m = [241;300] \end{cases} \tag{4.5.1}$$

During the first 20 years, the operator always receives the maximum of the feed-in tariff (FiT) depending on the quantity produced (Q) and the market value depending on power prices and inflation (P, I). The FiT constitutes a lower bound on the operator's revenue, as the operator receives the revenue in two parts. The direct marketer pays the monthly average market value of wind energy according to EEG Annex 1, 2.2.2. (EEG 2017). On top of that, if the guaranteed FiT is higher than the market value, the grid operator pays a market premium of $\text{FiT}_m(Q) - \text{Market value}_m(P)$.
As all four wind parks are assumed to start operation on December 31, 2018, they are all entitled to the same feed-in tariff. The German renewable energy law stipulates that onshore wind parks becoming operational between October and December 2018 receive 6.97 ct/kWh during the first five years. If a wind park's production (Q) in the first five years is below a certain defined reference production for the specific location and turbine type, this period can be prolonged for several years

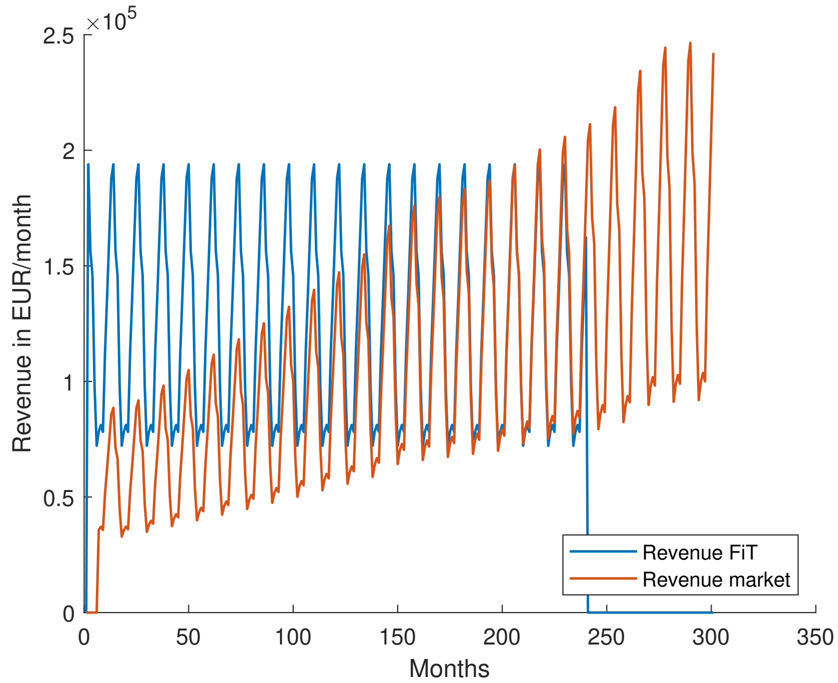


Figure 4.5.6: Possible revenues in EUR/month from FiT and from the market for wind park 2.

depending on the amount of the shortfall. After that, the remuneration is lowered to 3.87 ct/kWh until the end of the 20th calendar year (EEG 2017, § 46.2, 46a).

From year 21 to 25, the wind park has to raise its revenues on the power market. It is widely assumed that operators therefore negotiate long-term power purchase agreements (PPAs) with traders, utilities or industrial firms. These contracts vary in their specifics and could contain fixed as well as floating price structures. For simplicity and in order to illustrate the impact of power prices, it is assumed that the PPA price is always equal to the conservatively estimated monthly market value of wind power (see section 4.5.1.2).

For median power price assumptions, the high FiT of 8.38 ct/kWh is initially competitive for all four wind parks. Wind parks 2, 3 and 4 produce relatively less than their reference production and therefore benefit from a prolonged high FiT, as illustrated in figure 4.5.6. After year 17, though, the assumed median PPA price overtakes even the high FiT of 8.38 ct/kWh and operators thus switch to the PPA. For wind park 1, this is already earlier the case, namely when the FiT is lowered to 3.87 ct/kWh after year 13 (see also figure 4.6.1b).

Overall the revenues from the FiT account for 61% of the total revenue per MW on average and PPAs for the remaining 39%.

4.5.3.3 Operating cost

Operating cost consists of the following main elements. An O&M contract ensures maintenance of the wind park and is usually signed for 15 to 20 years. The overall cost per MW amounts to 28% of

total opex on average. The contract is explicitly linked to both production and inflation, and the inflation indices used are incorporated in the inflation assumptions above.
After the end of the O&M contract, assumptions are made for the cost of maintenance to the end of the park's lifetime. Inflation indexation is assumed. The overall cost per MW of O&M cost after the service contract is 14% of total opex on average.
Lease of land is another substantial part of opex, accounting for 22% on average. Lease contracts are usually indexed on revenues and follow a fixed increasing schedule, which is why inflation indexation is not assumed.
The wind parks analysed use an outsourcing model for technical supervision and accounting, which is common for financial investors. Technical and commercial management on average account for 5 and 3% of total opex per MW respectively, and both parameters are indexed to inflation.
The cost of decommissioning the wind park after 25 years is estimated in the permission documents. It amounts to 5% of opex per MW on average. Inflation indexation is assumed.
The remaining 23% of total opex per MW are distributed between costs for technical assessments, the commission on the bank guarantee for decommissioning, administrative costs of asset management, tax audit, insurance, power consumption and direct marketing.

4.5.3.4 Tax

All four wind parks are limited partnerships (KG) and therefore only liable to pay trade tax - and not corporate tax - under German law. The quarterly tax is

$$\text{Tax}_q(\text{Q, P, I, D}) = \text{Collection rate} \cdot \text{Tax base} \cdot \text{Tax reference}_q \tag{4.5.2}$$

with $q = [1;75]$.
The collection rate is a number between 2.9 and 4.55 depending on the location of the wind park and the tax base is equal to 0.035. The tax reference is based on a figure derived from the quarterly EBT, with

$$\text{Tax reference} = \text{EBT}_q + \text{Tax additions}_q \tag{4.5.3}$$

$$\text{EBT}_q(\text{Q, P, I, D}) = \text{Revenue}_q(\text{Q, P, I}) - \text{Opex}_q(\text{Q, P, I}) - \text{Depreciation}_q(\text{Q, P, I, D}) - \text{Interest}_q(\text{D}) \tag{4.5.4}$$

Tax additions include half of the lease, the full interest payment and the loss carry over of negative EBT from the previous period (Gewerbesteuergesetz 2009). Usually tax starts to become due after all the investment cost is depreciated and the debt is paid off, as figure 4.5.7 illustrates.

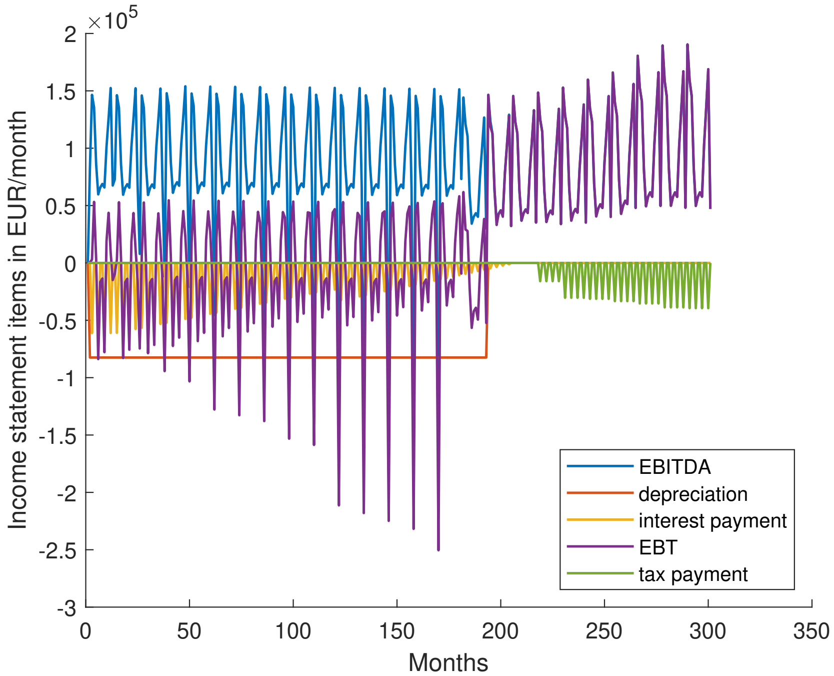


Figure 4.5.7: EBITDA (calculated as revenue-opex), EBT and the resulting tax payment at wind park 2 in EUR/month.

4.5.3.5 Investment cost

The investment cost consists mainly of the acquisition price (97% of investment cost on average), which is obtained endogenously for a fixed hurdle rate and median assumptions for production, power price, inflation and interest. The remaining part of investment cost consists of various transaction costs.

4.5.3.6 Net debt service

The wind parks come with two to four long-term loans with an average amount of 3.09 mio EUR each. The maturities of the loans are between 5 and 19 years with 14.5 years on average. Annual interest is at 1.86% and the period of fixed interest is 11.5 years on average for each loan. The debt schedule of each wind park is calculated according to the interest and redemption specifications laid out in the loan contracts. Figure 4.5.8 shows the different cash-flows related to debt.

4.5.3.7 Reserve payments

The debt service reserve is a minimum liquidity stipulated by the loan contracts. It is expressed as either an absolute amount or 50% of interest and redemption of the preceding year. It is built up over time from the initial liquidity of the wind park and cash-flows as they arise after serving opex, tax, investment cost and debt.

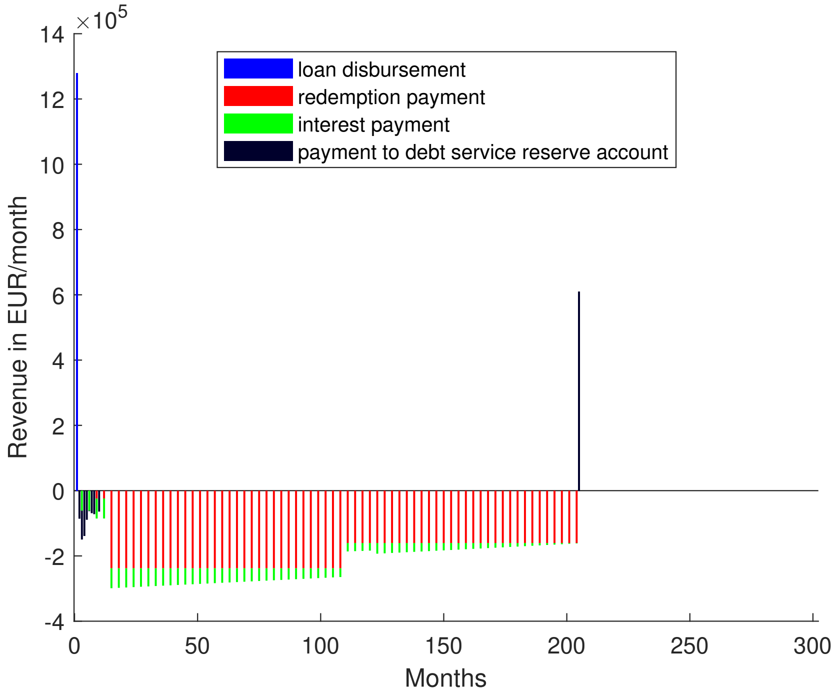


Figure 4.5.8: Cash-flows related to debt at wind park 2 in EUR/month. The loan disbursement in the first month has been shrunk by factor 10 for illustration purpose.

4.6 Results

In the following, the wind parks' payout returns are calculated for a range of scenarios with the acquisition price fixed as described in the model section. In order to understand the levers through which the payout returns are impacted, the cash-flow components in a specific scenario are discounted by the median hurdle rate and compared to those in the median scenario for each production, power prices, inflation and interest. For any cash-flow component, such as revenues or opex, a ratio is calculated as follows. The ratio for the median scenario is one by definition.

$$\text{Cash-flow ratio}_{\text{Scenario}_i} = \frac{\sum_{t=0}^{T} \text{Cash-flow component}_{t,\text{Scenario}_i} \cdot (1+\text{IRR})^{-t}}{\sum_{t=0}^{T} \text{Cash-flow component}_{t,\text{Scenario}_{\text{median}}} \cdot (1+\text{IRR})^{-t}} \tag{4.6.1}$$

with operating years $t = [1; T]$; $T = 25$.

4.6.1 Production

Uncertainty in energy production has the highest impact on the shareholders' payouts: the return varies from 2.8 to 10.1% per year (figure 4.6.1a).

The mechanism is simple. Higher production means higher revenues, as apparent in the comparison values for different scenarios, due to a higher amount of kWh produced (figure 4.6.1c). In some cases, there is also an additional indirect effect. Wind park 1 and 4 have an incentive to exit the FiT earlier and access the power market for higher production, because the FiT itself is inversely correlated with the quantity produced, as explained in the section on revenues. Under the current German renewable energy law, policy makers partly balance out low revenues due to unfavourable locations by an increased FiT per kWh (EEG 2017). Higher production means a lower FiT, which can make an earlier market entry attractive (figure 4.6.1b).

Operating costs (which are partly indexed to production and revenues), taxes and the payments into the debt service reserve also increase with increasing production, but they do not offset the increase in revenues (figures 4.6.1d to 4.6.1f). Investment cost and net debt service by definition do not react to an increase in production.

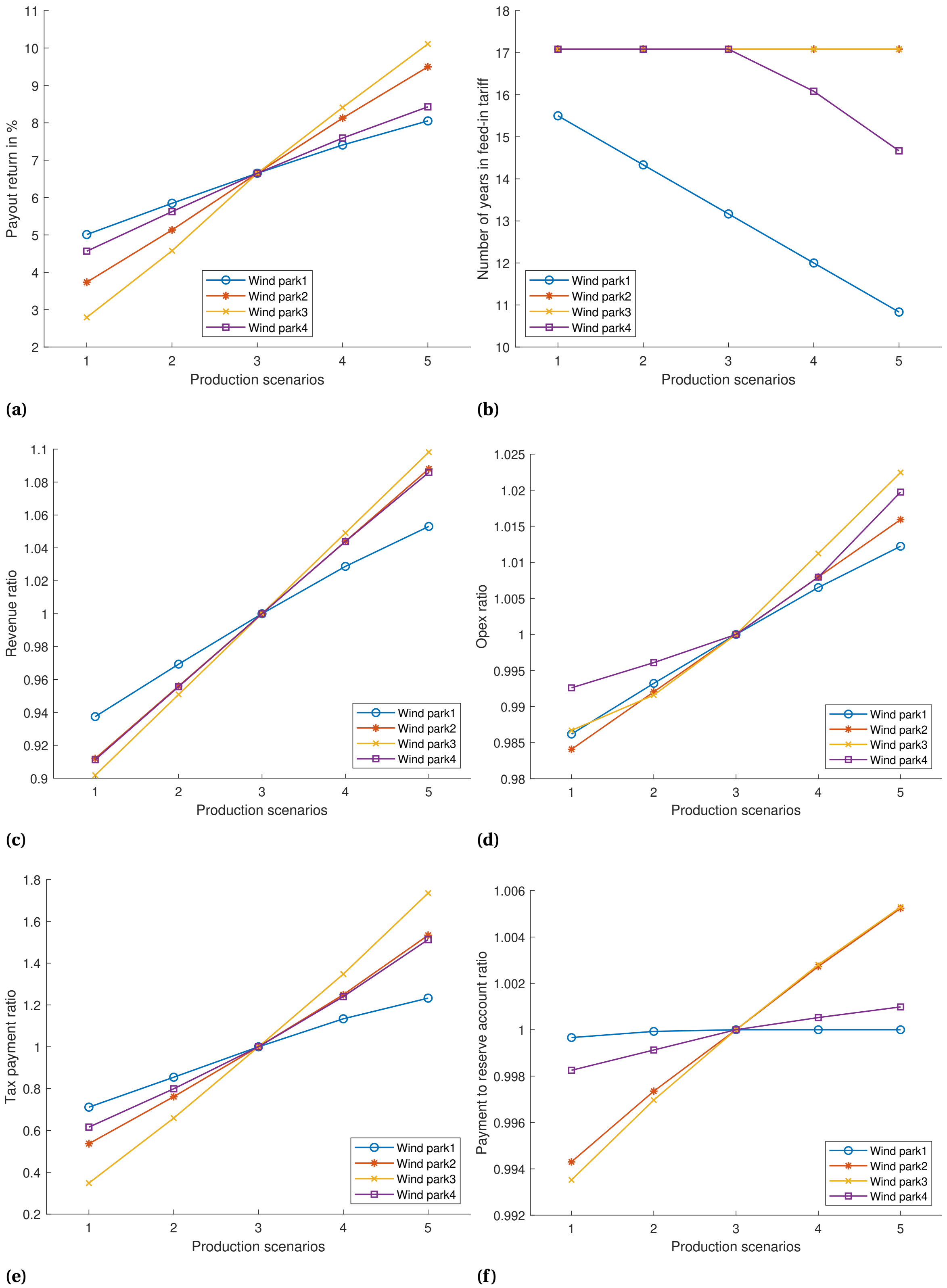


Figure 4.6.1: Payout return in %, number of years in the feed-in tariff and main cash-flow ratios for different production scenarios.

4.6.2 Power prices and wind market values

Higher power prices and wind market values have a high and positive impact on shareholder payouts: return varies between 3.6 and 9.3% per year (figure 4.6.2a).

Again, the increasing effect on payout returns works through revenues (figure 4.6.2c). The indirect effect is at play for power prices, too. Ceteris paribus, all wind parks exit the FiT earlier when the highest level of power prices is assumed. In the case of wind park 2 and 3, the effect is the most pronounced. In the lowest power price scenario, the operator uses the FiT for the full possible 20 years, whereas in the highest power price scenario only for nine years (figure 4.6.2b).

Operating costs (which are partly indexed to revenues) and taxes also increase with increasing power prices, but they do not offset the increase in revenues (figure 4.6.2d and 4.6.2e). Payments into the debt service reserve are not affected, most likely due to the late and moderate effect of power price (figure 4.6.2f). Investment cost and net debt service by definition do not react to an increase in production.

The high impact of power price uncertainty on payout returns in spite of secure revenues from the FiT for between nine and 20 years is notable. It means that once the FiT is phased out and plants have to secure their revenues on the private market, as already the case for example in Spain and the Nordic countries, hedging power price risk will be a major concern of wind power operators.

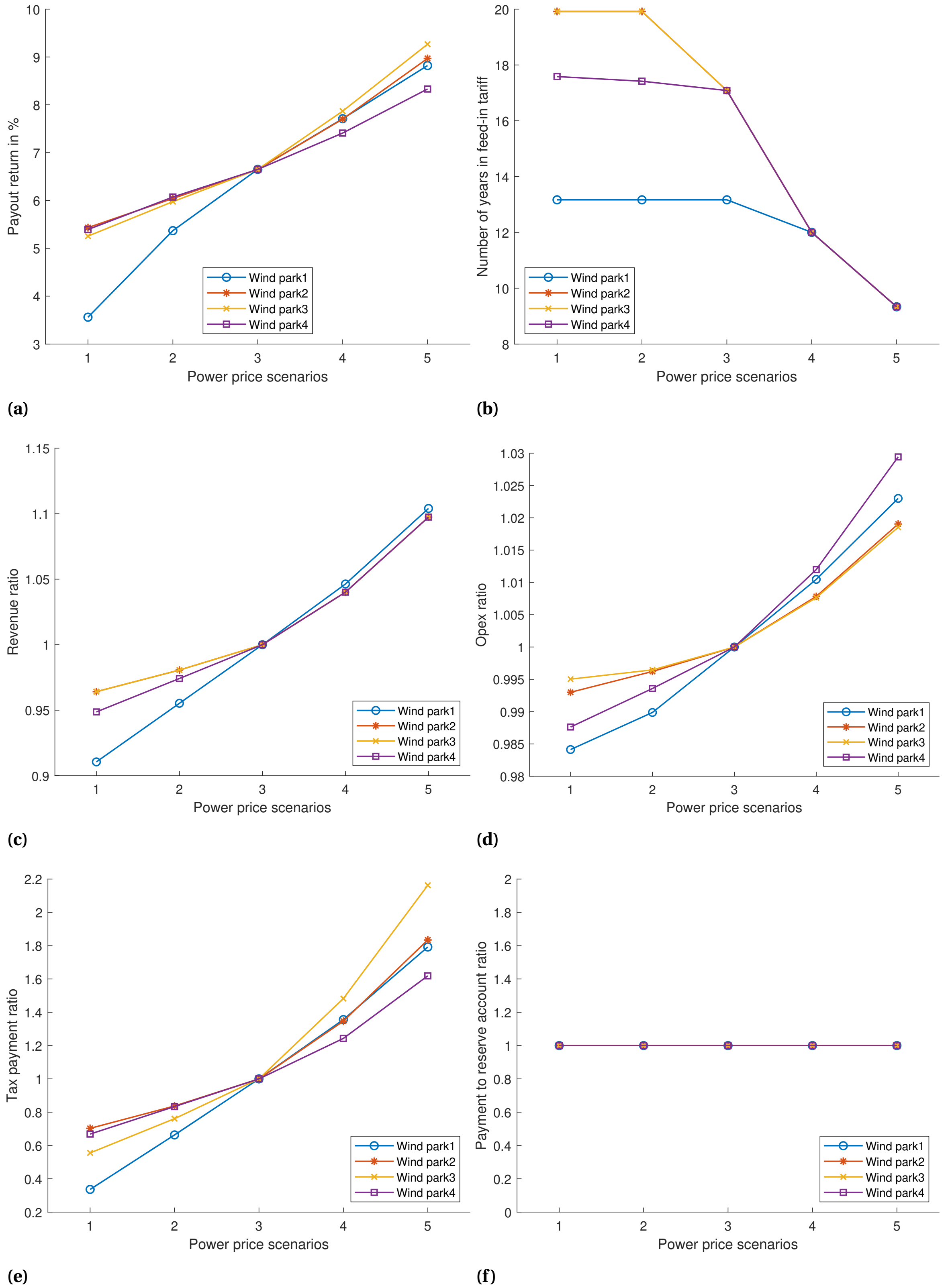


Figure 4.6.2: Payout return in %, number of years in the feed-in tariff and main cash-flow ratios for different power price scenarios.

4.6.3 Inflation

Inflation has a medium and generally positive impact on equity payout returns: it varies from 5.0 to 8.4% per year. A "bath tub curve" can be observed for wind park 2 and 3. The payout return has its minimum at the median inflation scenario and slopes steeply upwards for higher inflation (figure 4.6.3a). For higher hurdle rates, this effect becomes even more pronounced.

Inflation has a strictly positive impact on revenues. Similarly to power prices, the inflation effect works on the one hand via an increase of post-FiT market values. Indirectly, this also causes an earlier exit from FiT and access to power markets. This is because, as described in the hypotheses section, market revenues are indexed to inflation, whereas the FiT is not (EEG 2017). Ceteris paribus, higher inflation makes market prices more attractive relative to the fixed FiT. The effect is especially pronounced for wind park 2 and 3: for the lowest two levels of inflation, the parks stay in the FiT regime for the maximum period of 20 years, as opposed to only less than 12 years for the highest level of inflation (figure 4.6.3b).

When wind parks are in the FiT regime for a long time, overall revenues are less impacted by inflation and the slope of revenue to inflation is therefore comparatively flatter for low inflation at wind park 2 and 3 (figure 4.6.3c). Opex, on the other hand, is steeply increasing in inflation at wind park 2 and 3 (figure 4.6.3d). In combination, the flat revenue curve and steep opex at wind parks 2 and 3 lead to a slightly negative relationship of payout return with lower than expected inflation and a positive relationship for higher than expected inflation, as also reflected in the slope of tax payment (figure 4.6.3e).

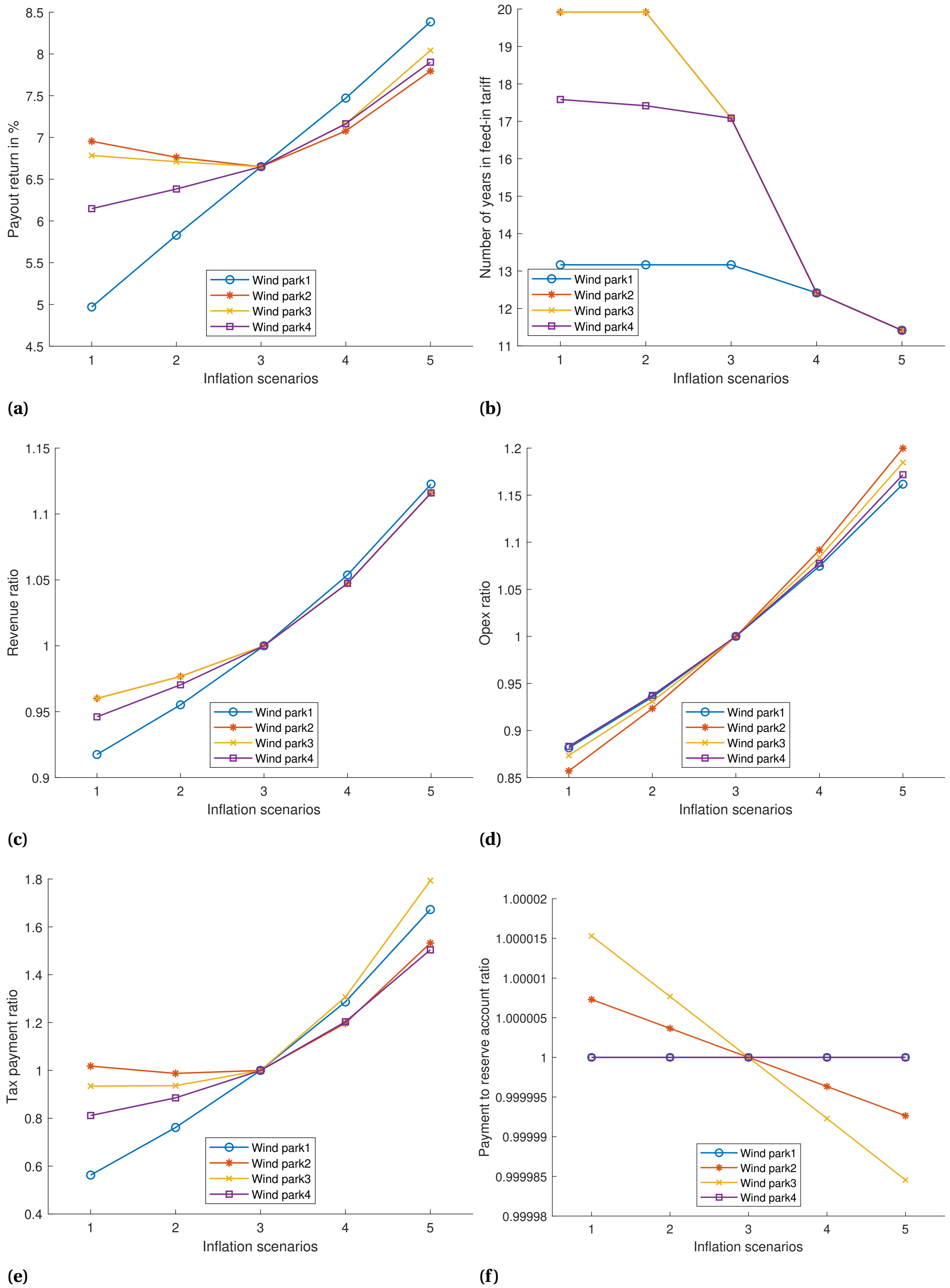


Figure 4.6.3: Payout return in %, number of years in the feed-in tariff and main cash-flow ratios for different inflation scenarios.

4.6.4 Interest

Interest rate scenarios have a negative but small impact on shareholder payouts: the return only varies between 7.0% per year for the lowest interest rate scenario and 6.2% for the highest one (figure 4.6.4a).

Interest rate changes impact payout returns via only one channel. Higher interest rates mean higher interest payments, with a negative effect on payouts. In the case of wind park 1, due to the signing of an interest rate swap contract over the full duration of the loans, there is no interest rate risk (figure 4.6.4a). Higher interest rates also mean lower tax payments, a positive effect not fully compensating for the effect on interest payments (figure 4.6.4c). The debt service reserve payment is not sensitive to interest rate scenarios due to the small overall effect (figure 4.6.4d).

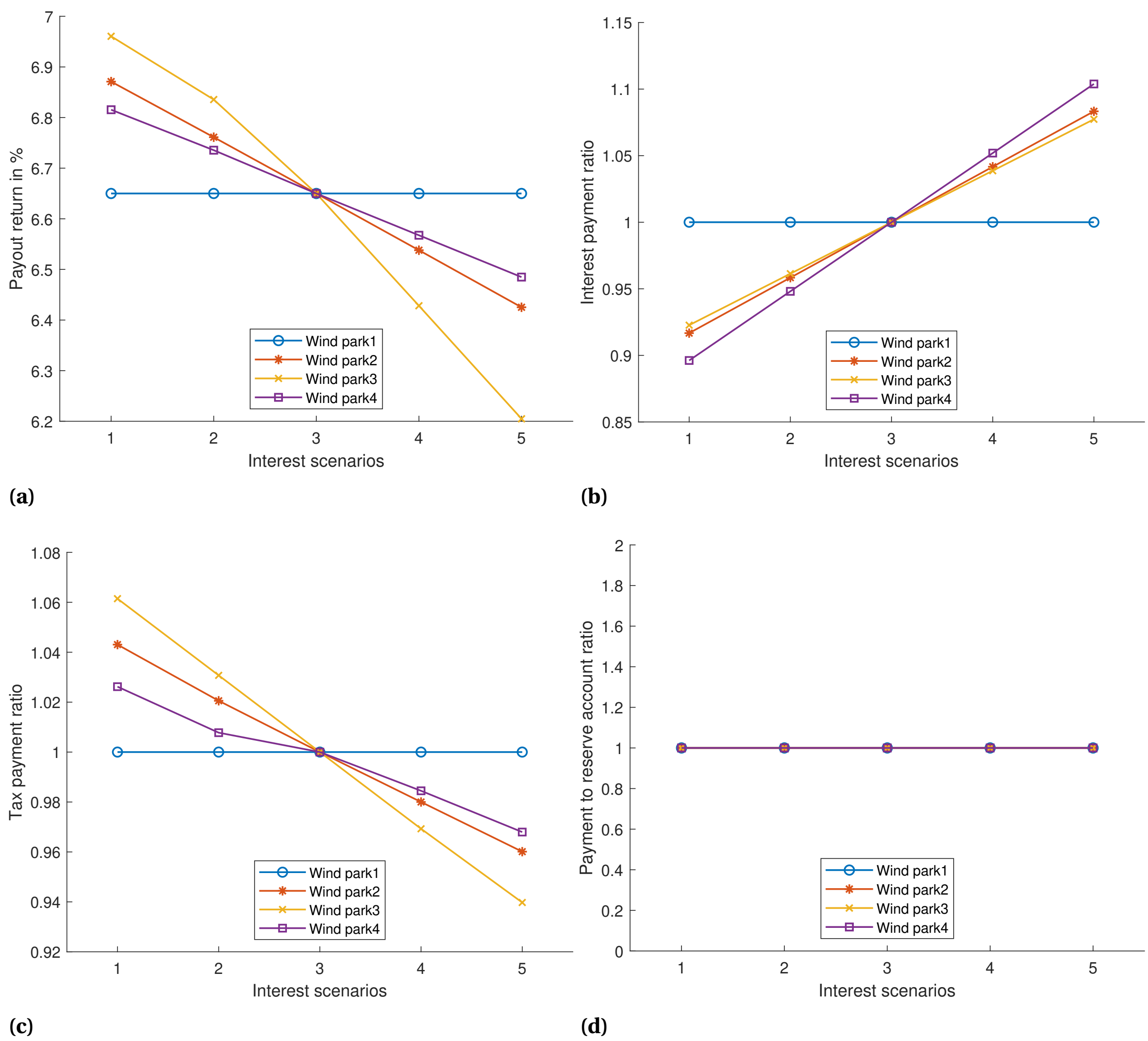


Figure 4.6.4: Payout return in % and main cash-flow ratios for different interest scenarios.

The results suggest that interest rate risk is no major concern for wind parks built under the current German FiT regime. This could change, however, once the FiT is further lowered, shortened or phased out and plants have to secure more of their revenues via PPAs. With PPAs of five to 10 years instead of 20 years guaranteed FiT, loan tenures might shorten and interest rate risk might become a higher priority for wind park operators (Interview 2018, Interview 2019).

4.7 Discussion

Uncertainty in energy production has the highest impact on the shareholders' payouts: the return varies from 2.8 to 10.1% per year. On the one hand, production affects revenues directly via a change of quantities remunerated. On the other hand, there is also an indirect effect. Higher production pushes some wind parks to exit the FiT and access the power market, because the FiT per kWh is inversely correlated with the total kWh produced.

The high sensitivity of wind park profits to production uncertainty is well known, even though its impact on equity returns has not been analysed in the literature so far. Investors and asset managers can respond to this in three ways. First, they could add a risk premium by using more conservative production estimates like the P90 value or deducting a percentage from P50 or P75. This, however, might endanger their ability to win acquisition when bidding for a wind park, a balance which might be difficult to strike. Second, financial asset managers could try to become more attuned to the technical details of wind power projects. This could entail analysing the quality of different wind assessments in depth prior to an acquisition, commissioning own independent assessments or requesting from policy makers to enhance quality controls and independence of assessments, thereby compressing the normal distribution of production to a narrower range. A third possibility, already practised by many investors, is to combine different locations in one portfolio or add further technologies like solar PV in order to reduce overall production risk.

Power prices and the resulting market values have a high and positive impact on shareholder payouts: return varies between 3.6 and 9.3% per year. Again, the increasing effect on returns works through revenues and indirectly through the FiT, as wind parks exit the FiT earlier for higher levels of power prices.

The high impact of power price uncertainty on payout returns in spite of secure revenues from the FiT for between nine and 20 years is notable. Once the German FiT is phased out and plants have to secure their revenues fully on the private market, hedging power price risk will be a major concern for wind power operators. Financial investors will likely pursue fixed price PPA contracts instead of the floating PPA prices indexed to power prices, which were assumed here.

Inflation has a medium and generally positive impact on equity payout returns: it varies from 5.0 to 8.4% per year. A "bath tub curve", with the lowest return not at the lowest inflation rate but somewhere in the middle, can be observed for wind parks that opt to stay in the FiT for a long time. In this case there is hardly any downside risk to inflation, as both lower and higher than expected inflation scenarios yield higher than expected returns. For wind parks operating on the free market, on the other hand, low inflation yields a comparably low return as revenue losses due to lower-than-expected inflation are higher than opex savings. A solution to hedge against inflation risk might be to mirror the indexation of operating costs by fixing an equivalent indexation for revenues in the PPA contract.

Interest rate scenarios have a negative but small impact on shareholder payouts: the return only varies between 7.0% per year for the lowest interest rate scenario and 6.2% for the highest one. Higher interest rates affect payout returns via higher interest payments, with a negative effect on payouts.

The results suggest that interest rate risk is not a major concern for wind parks built under the current German FiT regime. This could change, however, once the FiT is further lowered, shortened or phased out and plants have to secure more of their revenues via PPAs. With PPAs of five to 15 years instead of a 20 years guaranteed FiT, fixed interest rate periods and loan tenures might shorten and interest rate risk might become a higher priority for wind park operators.

4.8 Conclusion and policy implications

This paper has quantified the effect of production, power price, inflation and interest rate risk on wind park equity returns. It contributes to the energy economics and finance literature by presenting a financial investor perspective on production and macroeconomic risk in wind energy. To policy makers the results offer a deeper understanding of equity investors' needs in order to harvest their available capital for reaching renewable energy targets. This understanding is crucial if policy makers want to reach climate targets while at the same time phasing out renewable energy policy support.

The results underline the importance of energy production and power prices: shareholder payout returns range from 2.8 to 10.1% and from 3.6 to 9.3% respectively for a reasonable variation in production and power prices. Inflation has a medium and ambiguous impact depending on the time frame that wind parks operate under the guaranteed feed-in tariff regime. A possible increase in interest rates plays only a limited negative role for existing German wind park equity returns.

It is likely that power price, inflation and interest rate risks will increase if governmental support policies are further reduced. Further research is needed in order to determine how exactly equity payouts will react. It is concerning, though, that even for wind parks under the feed-in tariff for nine years or more, equity returns react strongly to moderate variations in power prices.

In this context it is crucial that the nascent PPA market develops the hedging strategies in order to avoid excessively risky equity returns and a possible retreat of financial investors from renewable energy markets. Policy makers can play a role in facilitating appropriate risk allocation, by, for example devising long-term reliable policies and supporting the standardisation of PPA contracts. What cannot be concluded from this paper is whether expected returns are sufficient for institutional investors or project developers to continue investing in German wind onshore. Per construction, the model assumes that equity investors can buy the wind park at their required expected return from project developers. It is left for future research to determine whether both project developers and financial investors will be able to earn their cost of capital in renewable energy markets with less or no policy support.

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4.10 Appendix

4.10.1 Wind park specific data

Table 4.1 contains the descriptive statistics of the most important wind park specific data for all four wind parks. All values are given as a sum over the entire lifetime of 25 years.

Parameter	Unit	Mean	Standard deviation
MW per wind park	MW	7.22	2.17
Leverage at acquisition	Percent	74.37	9.77
Number of years of FiT	Years	16.10	1.96
Revenue per MW	EUR	4’247’853.37	676’575.34
Revenue from FiT per MW	EUR	2’579’814.34	325’227.82
Revenue from market per MW	EUR	1’668’039.02	546’381.90
Opex per MW	EUR	1’336’038.56	110’263.61
Years of O&M contract	Years	17.50	1.73
O&M contract per MW	EUR	368’799.70	12’861.77
O&M cost after contract per MW	EUR	193’773.16	96’091.69
Lease per MW	EUR	296’714.87	92’643.67
Technical management per MW	EUR	66’977.45	19’344.40
Commercial management per MW	EUR	39’792.10	9’960.83
Decommission cost per MW	EUR	62’795.88	15’502.95
Tax payment per MW	EUR	105’173.45	37’294.58
Investment cost per MW	EUR	1’756’666.44	271’859.92
Number of loans per wind park	Number	3.00	0.82
Loan amount per MW	EUR	1’265’483.93	213’604.53
Loan period per wind park	EUR	14.46	4.75
Fixed interest per loan	Percent	1.86	0.38
Interest payment per MW	EUR	236’558.21	45’647.66
Debt service reserve account per MW	EUR	49’640.90	27’434.03
Initial cash per MW	EUR	27’210.62	33’089.91

Table 4.1: Data for the four wind parks analysed.

Curriculum Vitae

Lena Hörnlein

Born: August 26, 1985 in Würzburg, Germany

Education

2014–2020	**PhD Candidate** Department for Banking and Finance, University of Zurich, Switzerland
2011–2012	**MSc Environmental Economics and Climate Change** London School of Economics and Political Science, UK
2006–2010	**BA Philosophy and Economics** University of Bayreuth, Germany